JOINT PRE-FILED REBUTTAL TESTIMONY

OF

PHILIP J. WALNOCK

AND

WANDA E. REDER

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

<u>Philip J. Walnock</u>

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

A. My name is Philip J. Walnock. My business address is 2 North 9th Street, Allentown, PA 18101.

Q. Are you the same Philip J. Walnock who submitted pre-filed direct testimony in this docket?

A. Yes.

Q. Are you still the Director, Product Portfolio – Field Operations & Metering of PPL Services Corporation ("PPL")?

A. Yes.

Q. During your time with PPL, have you worked on advanced metering infrastructure ("AMI") deployment?

A. Yes. As described in our pre-filed direct testimony, from 2015-2019, I was responsible for leading the overall implementation of PPL Electric Utilities Corporation's (hereinafter "PPL Electric") Smart Meter Implementation Plan, where approximately 1.45 million automated meter reading ("AMR") meters were replaced by second-generation AMI meters in Pennsylvania.

Q. How is your experience relevant to Rhode Island Energy?

A. The advanced metering functionality ("AMF") implementation plan in the AMF Business Case mirrors closely the successful Pennsylvania deployment that I oversaw. I am overseeing the Rhode Island AMF deployment planning using the extensive project experience that I gained while working on the Pennsylvania deployment.

<u>Wanda Reder</u>

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

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

Q. Are you the same Wanda Reder who submitted pre-filed direct testimony in this docket?

A. Yes.

Q. Are you still President and CEO of Grid-X Partners?

A. Yes.

Q. Are you still testifying on behalf of Rhode Island Energy?

A. Yes.

II. Purpose, Background and Structure of Testimony

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

A. The purpose of our joint rebuttal testimony is to respond to issues raised in the direct testimony of the intervenors in this docket. Specifically, our rebuttal testimony responds to the direct testimony of the Rhode Island Division of Public Utilities and Carriers (the "Division"), the position statement of the Rhode Island Office of Energy Resources ("OER"), and the direct testimony of Michael Murray on behalf of the Mission:data Coalition ("Mission:data"). Rhode Island Energy has filed, contemporaneously with our testimony, a separate memorandum in response to the Statement of Position of the Rhode Island Attorney General (the "Attorney General").

Q. How is your testimony structured?

A. Sections I and II include an Introduction and the Purpose, Background, and Structure of the Testimony, respectively. Section III discusses the parties' consensus regarding AMF. Section IV addresses the critical role that AMF plays in meeting Rhode Island climate goals. Section V explains the Company's proposed timing and process for implementing AMF in Rhode Island, including the basis for the Company's position that implementing AMF is an urgent need of the State. Section VI addresses the impact of AMF on safety and reliability in Rhode Island. Section VII addresses various concerns regarding Time-Varying Rates ("TVR"), including the timing and process for implementing TVR in

Rhode Island. Section VIII discusses the Benefit-Cost Analysis ("BCA") and the Docket 4600 Framework and responds to the Division's comments about the BCA. Section IX addresses how the Company will be held accountable for the proposed benefits outlined in the AMF Business Case. Section X presents additional topics that are best addressed in future dockets, including Green Button Connect ("GBC"), Home Area Networks ("HANs"), and so-called Distributed Intelligence ("DI"). Finally, Section XI is the conclusion.

III. <u>The Parties' Consensus Regarding Advanced Metering Functionality</u>

Q. What do you view as the key take-away from the intervenors' testimony?

A. The Company is very pleased that all parties who submitted testimony or position statements support the implementation of AMF in Rhode Island.

For example, the Division's testimony states unequivocally that, "the Division supports the installation of AMF." Joint Direct Testimony of William F. Watson, Ph.D and Robin W. Blanton, P.E. [hereinafter "Div. Testimony"] 10:10. Likewise, subject to its recommendations, OER "supports the AMF Business Case Proposal by Rhode Island Energy" and notes that, "Rhode Island will struggle to meet its clean energy and climate obligations" without the future system improvements that AMF makes possible. OER Position Statement, 1. Although the Attorney General's Statement of Position is less definitive, he nevertheless "agrees that major investment in technology needs to be undertaken expeditiously to enable accelerated electrification." Attorney General's Statement of Position [hereinafter "AG Statement"], 2. And Mission:data's testimony presupposes the implementation of AMF technology, thereby also signaling support for the implementation of AMF. The Company is pleased by this fundamental agreement that AMF implementation is necessary and desirable.

Q. Are there any other key takeaways you would like to highlight?

A. Yes. We would like to highlight that, although the Division proposes certain adjustments to the Company's BCA, the Division still arrives at a positive BCA. Thus, even under the Division's more restrictive analysis of the benefits, the Company's AMF implementation proposal is cost-effective. Div. Testimony 33-34. Although the Company does not agree with the Division's adjustments to the BCA, as we discuss later in this testimony, even if the Commission accepted all of them, the BCA still would support approval of the AMF Business Case for the benefits AMF will deliver to Rhode Island Energy customers. The Division concedes this point in its response to Data Request PUC 1-1(a), (c).

Q. Are there other areas of agreement among the parties with respect to the Company's proposed AMF Business Case?

A. Yes. The parties agree that Rhode Island Energy should move forward expeditiously with

AMF implementation. The Division in particular states that it "supports the Company's proposed timeline" and rejects the suggestion that the Company should defer AMF implementation. Div. Testimony 12:9-11. In response to the Commission's request for the Division to provide an alternative timeline for the AMF implementation schedule, the Division proposed a staggered timeline as one option in its response to PUC 1-1(d). Although the Division characterized this longer timeline as a feasible option, in that same response the Division also reiterated its support for the Company's proposed AMF timeline.

Although OER and the Attorney General do not explicitly state that they agree with the Company's proposed implementation timeline, their comments demonstrate support for beginning AMF implementation expeditiously. OER, for example, requests that the Commission "prioritize a prompt, thoughtful implementation" of TVR and asks that the Commission require the Company to submit a proposal for implementing TVR by March 31, 2024, more than a year earlier than the Company proposes and before the Company will have completed the AMF meter rollout under its proposed timeline. OER Position Statement 2. OER's requests suggest that AMF implementation occur at least as rapidly as the Company proposes. Likewise, the Attorney General notes his view that AMF implementation was "delayed" by the acquisition of the Company by PPL Rhode Island Holdings, LLC. AG Statement at 2-3. The Company addresses this contention separately in its response to the AG Statement, but it signals that the Attorney General seeks to advance AMF implementation promptly and would not want further delay.

Q. What other areas of agreement do you observe among the parties?

A. We see two additional areas of agreement among the parties. First, the parties agree that AMF implementation should make available 15-minute interval usage and voltage data in near-real time. Div. Testimony 21:13-14; OER Position Statement 2; Testimony of Michael Murray on Behalf of Mission:data Coalition [hereinafter "Mission:data Testimony"] 11:4-13. This is consistent with the Company's AMF Business Case. The AMF Business Case proposes the use of next-generation metering technology to capture and transmit 15-minute interval electric meter data to Rhode Island in near-real time through an RF mesh routing communications network. This means the data will be brought back from the meter, through the network, and to the head-end system every 15-20 minutes, making raw data available to customers on a customer portal within 30 to 45 minutes of actually using the electricity.

Q. Why is near-real time 15-minute interval data important?

A. There are several reasons. First, readily available 15-minute interval data provides customers with near-real time insights into their energy usage. This allows customers to evaluate their energy usage and make adjustments in a manner that may reduce their energy costs. The availability of this data also allows the Company to provide customers with more specific insights, such as high-bill alerts, regarding their energy usage. Increased customer awareness and engagement from the availability of near-real time 15-minute interval data also can increase the adoption and success of TVR, energy efficiency, and demand response initiatives.

Second, 15-minute interval data will improve the Company's operational efficiency and enhance safe and reliable operations. The Company can use this data to understand in near-real time the operating state and condition of the electric distribution system and distributed energy resources ("DER"). Having near-real time information about usage and demand on the system allows the Company to respond more expeditiously to issues that may arise on the electric distribution system. For example, having this information can allow the Company to anticipate and address hidden load in switching schemes. Additionally, because this granular data allows the Company to make more accurate load-flow calculations, it can use these calculations to better analyze power flows and optimize electric distribution system utilization. In other words, the Company can use the information from this technology to better manage the electric distribution system, thereby relieving or avoiding thermal or voltage constraints to defer or avoid entirely investing in additional traditional infrastructure, such as substation upgrades.

Third, 15-minute interval usage and voltage data will improve electric distribution system planning. Instead of using generic load shapes for planning analyses, the Company will be able to use actual loading and voltage profiles throughout the electric distribution system. As the Division stated in its direct testimony, "AMF data will dramatically improve the CYME engineering software model, and, thus, the Long-Range Planning and ISR Plans." Div. Testimony 21:13-14.

Fourth, 15-minute interval data makes TVR possible. We discuss in greater detail below our disagreement with the Division's assertion that AMF is not necessary to implement TVR. At a high level, although Rhode Island Energy's existing AMR technology (with the addition of triple-ERTs and programming) is capable of establishing rudimentary time blocks to implement some basic time of use rates, AMR is not capable of the sophisticated variable pricing that will incent demand shift sufficiently to manage load and enable the most effective integration of DER on the electric distribution system. Those types of pricing structures require the detailed 15-minute interval data that is available with AMF – but not with the current AMR meters.

Q. How did the other parties demonstrate their agreement with the importance of 15-minute interval data?

A. The other parties all refer favorably to the benefits unlocked by 15-minute interval data.

The Division highlights that 15-minute interval data will dramatically improve electric distribution system planning. Div. Testimony 21:13-14. OER emphasizes the importance of TVR "to shift consumption patterns" for Rhode Island to achieve the 2021 Act on Climate emissions reduction targets. OER Position Statement 2. Mission:data highlights the opportunity that "granular and real-time data" creates for energy conservation solutions. Mission:data Testimony 11:4-13.

Q. What does this consensus around the need for near-real time 15-minute interval data mean for the metering solution required?

A. To get 15-minute interval data in near-real time, the Company needs to implement AMI meters, version 2.0, along with the Wi-SUN network. This is what the Company proposed and used in calculating the BCA. As the Company explained in response to PUC RR-2 and discussed at the May 10, 2023 Technical Session, version 2.0 AMI meters are different from what the Company's affiliates in Pennsylvania and Kentucky have implemented or begun to implement. Pennsylvania and Kentucky use version 1.0 AMI meters. The version 1.0 AMI meters are not capable of providing 15-minute interval data in near-real time. Instead, version 1.0 AMI meters return interval data every four to six hours. The ability to return data in near-real time also depends on the implementation of the Wi-SUN network, which is four times faster than the network in Pennsylvania.

Q. Was there another area of agreement you wanted to address?

A. Yes. The Division agrees with the Company's selection of Landis & Gyr to provide meters and related technology and services for AMF implementation. The Company's indirect parent, PPL Corporation ("PPL"), has worked with Landis & Gyr for nearly ten years, and Landis & Gyr has provided AMI meters to PPL's Pennsylvania and Kentucky affiliates. The Joint Pre-Filed Supplemental Testimony of Philip J. Walnock and Stephanie A. Briggs describes in detail the synergies and benefits to Rhode Island of using Landis & Gyr for Rhode Island AMF implementation. The Division has testified that, "Engineering and economic logic would support that Rhode Island utilizing the same AMF system and design as the rest of the PPL system may have some advantages." Div. Testimony 13:10-11. According to the Division, "there is no compelling reason to deviate from the PPL AMF selection and, thus, it should provide the most expeditious implementation path with the least likelihood of extensive implementation problems and customer disruptions." *Id.* 13:21-14:1. As outlined in the Joint Pre-Filed Supplemental Direct Testimony of Philip Walnock and Stephanie Briggs, we agree that moving forward with Landis & Gyr to provide the meters and related technology offers the greatest value to Rhode Island.

Q. Is there agreement among the parties that AMF implementation is important for achieving the State's climate goals?

A. Yes. The Division, OER, and the Attorney General all have stated that they consider AMF necessary to achieve the State's Climate Mandates. OER, for example, states that it "supports the AMF Business Case Proposal" by the Company, "echoing the opportunity investing in AMF represented as part of the climate objective to modernize the state's electric grid in the McKee Administration's Rhode Island 2030 plan." OER Position Statement, 1. Likewise, the Division states in its direct testimony that AMF deployment will "provide a very sizable incremental boost in achieving the climate mandates that the Rhode Island legislature has enacted." Div. Testimony 26:1-2. The Attorney General also notes that the Company "has expressly considered the Act on Climate in presenting its business case" and "agrees that major investment in technology needs to be undertaken expeditiously to enable accelerated electrification." AG Statement, 2.

IV. <u>AMF as a Critical Stepping Stone to Achieving Rhode Island's Climate Goals</u>

Q. You have described the general agreement among the parties that the Company should move forward expeditiously with AMF implementation, and the AMF implementation is important for meeting the State's climate goals. Why is AMF implementation important for meeting the State's climate goals?

A. The Company described the relationship between AMF implementation and achieving

Rhode Island's climate goals in the Pre-Filed Direct Testimony of David J. Bonenberger (hereinafter, "Bonenberger Testimony"). At that time, Mr. Bonenberger highlighted the 2021 Act on Climate, which set forth enforceable, statewide, and economy-wide greenhouse gas emissions mandates that require Rhode Island to reduce greenhouse gas emissions by 45 percent below 1990 levels by 2030, 80 percent by 2040, and to achieve net-zero emissions by 2050. Bonenberger Testimony 6:14-17. Mr. Bonenberger also referred to the 2022 amendments to the Renewable Energy Standard, which require 100 percent of electricity used in the State to be generated by renewable resources by 2033. *Id.* 6:17-20. The testimony and AMF Business Case refer to these collectively as the "Climate Mandates."

Since that time, a little more than six months ago, Rhode Island has accelerated its shift to renewable energy even further. For example, on May 9, 2023, the Rhode Island Governor issued an Executive Order (hereinafter, "2023 Executive Order") calling, among other things, to reduce emissions from a 2014 baseline associated with fossil fuels used in buildings and cars by 40 percent by 2030 and to move 25 percent of the light-duty state fleet to zero-emissions vehicles by 2030. Executive Order 23-6 (May 9, 2023). Just one day later, the Rhode Island Department of Environmental Management released draft regulations (hereinafter, "Draft RIDEM Regulations") intended to increase the sale of new zero-emissions vehicles to 100 percent by 2035. In order to keep pace with Rhode

Island's aggressive and nation-leading Climate Mandates, the Company's electric distribution system must be ready to manage the changes in electric power generation and consumption that likely will occur as a result. AMF implementation and the data it will provide for operations and planning purposes, as well as the flexibility it will provide in demand management through sophisticated TVR and customer energy management enablement, are important aspects of readying the electric distribution system. As such, implementation of AMF should begin expeditiously.

Q. How does AMF help the State achieve the Climate Mandates?

A. AMF is necessary both in its own right to achieve the Climate Mandates and because of the functionalities that become available to the Company when AMF is combined with other technologies that the Company intends to implement on the electric distribution system. The shift in the volume, quality, and timeliness of information that AMF makes available to the Company and to Rhode Island Energy customers enables operational and planning improvements for the Company and behavioral options for customers that would contribute significantly to achieving the Climate Mandates.

Q. How does the shift in the volume, quality, and timeliness of information make a difference?

A. First, the Company expects that achieving the Climate Mandates will include continued increases in DER interconnections. Higher penetrations of DER interconnections increase the intermittency, uncertainty, and complexity of the electric distribution system. In the course of any given day, DER can cause unanticipated power flows or voltage fluctuations or compromise the effectiveness of protection schemes. The Company's electric distribution system operators currently cannot see or control these impacts, which can result in problems such as equipment failures and uncertainty during switching routines. Without the data provided by AMF, Rhode Island Energy system operators likely will not even know these events have occurred, let alone be able to address them. In the absence of the enhanced management capability that AMF data enables, the Company expects that it would have more limited ability to interconnect DER, or the costs for system upgrades needed to safely interconnect DER would increase potentially to the point of becoming prohibitive.

Q. Would enhancing the AMR meter system with additional infrastructure like grid-edge sensors provide the same level of visibility?

A. No. AMF meters incorporate grid-edge sensing that can detect voltage anomalies and pinpoint system outages. The current AMR meters do not have this incorporated technology. AMR meters do not provide near-real time information on system conditions, and grid-edge sensing only tells you what is happening where that specific piece of sensing equipment is on the system. AMF meters provide both – near-real time data at every single meter location. As a result, an electric distribution system using AMF meters provides higher sensing resolution than a system using AMR meters plus grid-edge sensors because AMF provides monitoring and visibility at every customer location, whereas AMR technology can monitor only at the location of the grid-edge sensor.

Q. Why else does the near-real time data provided by AMF infrastructure help the State achieve the Climate Mandates?

A. To be able to transition to electrification at the pace contemplated by the Climate Mandates, as well as the 2023 Executive Order and Draft RIDEM Regulations, significant investments will be needed to ready the electric distribution system to facilitate and manage the anticipated changes in electricity generation and demand. For example, this shift likely will result in accelerated adoption of electric vehicles. To ensure that the electric distribution system can be ready for this increase, the Company modeled an increased use of electric vehicles that would require 6,000 GWh of incremental electricity annually to ensure that the Company would be able to manage any level of electric vehicle adoption. Please see, for example, Bates page 52 of the AMF Business Case. Such an increase in electricity consumption will also require data to manage. The Company will need to counterbalance the strain on the electric distribution system and achieve greater system optimization by shifting electric vehicle charging demand to off-peak periods. Accomplishing this shift will require the enactment of dynamic pricing through complex time-varying rates. The near-real time 15-minute interval data made available through AMF makes these kinds of dynamic TVRs possible.

Q. What role do the TVR structures made possible by AMF play in meeting the Climate Mandates?

A. Based on the electric distribution system modeling the Company has performed in connection with the Grid Modernization Plan submitted to the Commission, the Company expects that TVR structures will be necessary for Rhode Island to achieve the Climate Mandates. To understand how the electric distribution system will need to evolve to achieve the Climate Mandates, the Company modeled how peak distribution system load and load shapes may change as the State moves to achieve its goals. The Company developed a scenario that assumes the State will achieve the legally required Climate Mandates and considered how to prepare the electric distribution system to be able to withstand the stressors that may result. As Rhode Island continues to shift to the electrification of vehicles and heat, the Company needs to prepare for the possibility that the peak electric distribution system load could nearly double by 2050 and that seasonal and daily load shapes will change dramatically. TVR structures help reduce demand spikes and flatten demand peaks by adjusting electricity prices to incent customer behavior by better reflecting the actual cost of both supply and delivery service. They also help customers save costs. Using TVR structures to shift demand can help defer building additional infrastructure that would otherwise be required to meet the increased demand.

These are just a few of the ways in which AMF in and of itself helps advance the State towards the Climate Mandates. Additional ways in which AMF does this are identified in the AMF Business Case as "foundational AMF capabilities."

Q. How does AMF combine with other technologies to advance the State further towards the Climate Mandates?

A. The Company discussed this in detail in Section 4 of the AMF Business Case regarding how AMF will integrate with potential grid modernization investments. As the Company said there, and as OER stated in its Position Statement, "AMF is an enabling technology that will allow critical future improvements, including the introduction of [TVR], more efficient and effective incorporation of variable generation resources, and improved system planning and reliability." OER Position Statement 1. The AMF Business Case identifies the ways that AMF combines with other technologies to create new functionalities as "AMF enabling capabilities" or "enhanced AMF capabilities."

Once the Company has access to 15-minute interval data, the Company can incorporate that data into other existing or proposed technologies. For example, the Company currently uses feeder-level data plus generic load shapes to model feeder performance. When the AMF data is combined with the advanced distribution management system ("ADMS"), the Company will be able to create actual loading and voltage profiles at all points along a feeder. With respect to DER planning, the Company's current interconnection analysis uses the DER nameplate capacity and compares it to localized system ratings with a minimum load value. The Company must use these values because it does not have data regarding the actual electric distribution system conditions that exist at the time of peak DER operations. AMF will allow the Company to perform daily load cycle analyses of existing DER sites to develop new, more specific assumptions for the interconnection analysis based on actual DER output and system conditions at the time of DER peaks. These refined assumptions and analyses may result in the availability of greater hosting capacity, which in turn provides opportunity for greater DER interconnectivity and decreased interconnection costs.

V. <u>AMF Implementation Timing and Procedures</u>

Q. You stated at the outset that the parties agree that Rhode Island Energy should implement AMF expeditiously. What is the Company's proposed project timeline?

A. As outlined in Section 8.1 of the AMF Business Case, the Company has proposed to implement AMF over three and a half years. The Company already has begun initial work to get "deployment ready," spending dollars at risk to be ready to implement AMF expeditiously.

Q. Why does the Company have a sense of urgency in implementing AMF?

A. We explained in our pre-filed direct testimony that the convergence of three factors supports the conclusion that now is the right time to invest in a system-wide transition to AMF meters.

First, the Company's existing automated meter reading infrastructure ("AMR") is reaching the end of its design life and becoming obsolete. Approximately 60 percent of electric encoder receiver transmitter ("ERT") and solid-state AMR assets currently in the field will reach the end of their estimated 20-year design life by the end of calendar year 2024. While the end of design life does not necessarily mean that the AMR assets will not work anymore, the end of design life marks the period of time that the designers specified the asset to operate reliably. While many of the AMR assets may operate beyond their average design life, one can reasonably expect that the failure rates will increase and over time replacement components will become increasingly difficult to procure.

Given the need to replace a majority of the meters in the field in the near term, the Company considers the most beneficial approach to be a full-scale, system-wide AMF implementation as discussed and recommended in the AMF Business Case in Section 3.2 and 3.3. Planning a full-scale AMF implementation brings numerous efficiencies and benefits that the Company cannot achieve through a targeted implementation. These include the benefits identified in the BCA. Further, having one metering solution improves the overall consistency of the system, which in turn means more consistent and reliable customer billing, customer interactions, metering inventory, and communications. The Company can achieve economies of scale by using a uniform metering technology that are lessened by having multiple metering systems in place over the long term. This is not to say that the Company cannot continue to operate the legacy AMR system during the transition to the AMF system. The Company can and will continue to do so. The Company recommends, however, that any continuation of the AMR system be done with the understanding and intention that such continuation is simply a stop-gap as AMF implementation occurs. As described in the AMF Business Case, the Company does not recommend adopting a plan to maintain multiple metering systems over the long-term (what the AMF Business Case refers to as "targeted" AMF implementation) because of the inefficiencies and loss of benefits such an approach entails. Nor is it the Company's contention that its proposed implementation schedule is the only schedule that is feasible. Rather, the Company has put forth an implementation schedule that it proposes best achieves the transition to AMF in the manner that delivers benefits efficiently and effectively.

Second, AMF provides functionalities that will help drive achievement of the State's Climate Mandates while continuing to operate the electric distribution system in a safe and reliable manner. Given that the first mandated emission reduction under the Act on Climate occurs in 2030, less than seven years from now, and that the Company has proposed to implement AMF over three and a half years, starting implementation as soon as possible will help ensure that these functionalities are available in a timely manner to help meet the Climate Mandates.

Third, as reflected by the OER Position Statement and the Mission:data testimony, customer expectations have evolved such that they expect to have access to detailed and frequent information about their energy usage. All the parties agree that the AMF meters enable the Company to deliver energy insights, personalized energy efficiency, and effective demand response programs to customers. For example, OER notes that AMF will facilitate "ensuring that customers can easily identify, purchase, and use products that connect to their [Home Area Network] to provide greater visibility into energy consumption and to automate the response of appliances and plug loads to price signals [which] will amplify the benefits of AMF and TVR." OER Position Statement, 4.

Similarly, Mission:data explains the many benefits of providing customers with near-real time data that can help change their energy-usage patterns and behaviors. MDC Testimony 28:13-29:9. The Division also states that, "The AMF metering system, when fully deployed, will allow greater data transparency through two-way communication on the RIE distribution system to both the Company and consumers. This data transparency will enable more efficient deployment of Company resources and strategies to reduce consumer energy usage." Div. Testimony 25: 20-23.

Q. The Division disagrees with the Company's sense of urgency for implementing AMF and states that the industry will continue supporting AMR meters for at least ten more years given the quantity of meters in service. How do you respond?

A. First, we want to clarify a possible misunderstanding by the Division. The AMR meters in the field are reaching the end of their design life, which is separate from their depreciated life and is not simply an accounting function. For Rhode Island Energy, the depreciation rate for AMR meters (plant account 370) is 22.4 years, but the design life for AMR meters is 20 years. As large quantities of meters reach and surpass their design life, we expect meter failure rates will increase. As the Company explained in its supplemental response to Data Request DIV 4-15, the rates of meter retirements and meter exchanges have both increased since 2020, as more and more AMR meters reach the end of their design life.

Second, when meters fail, the Company needs to replace them. Even if the Division is correct that the industry will support AMR meters for no less than ten years, replacing the current AMR meters with new AMR meters creates a significant risk that the new AMR meters become wholly obsolete and unsupported well before they reach the end of their design life, creating the risk of substantial stranded assets.

Q. The Division also suggests that the State's ability to meet the Climate Mandates will not suffer if AMF implementation is delayed. How do you respond to that contention?

A. The Division has not offered any evidence to support this opinion, and thus it is unclear how the Division expects the State will achieve the Climate Mandates without the data and functionality from AMF supporting the other efforts that will take place in furtherance of achieving them. From the Company's perspective, meeting the Climate Mandates will require a substantial and rapid increase in DER interconnection and adoption of electrification, such as electric vehicles and electric heat pumps. It is not reasonable to assume that interconnection and adoption rates will remain consistent with what they have been in the past. The Rhode Island Department of Environmental Management's recent release of draft regulations tightening tailpipe emissions requirements provides one point of evidence that these rates will increase. Delays may impact the State's progress towards achieving the Climate Mandates. As explained above, AMF is important to ready the electric distribution system to adapt to the changes in electricity generation and consumption that will result, and therefore the absence of AMF would inhibit some of the achievement efforts.

Q. The Division's response to Data Request PUC 1-1(d) proposed an alternative AMF implementation timeline that would extend the AMF implementation over a longer period than the three and a half years proposed by the Company. What effect would extending AMF implementation have on the benefits and costs the Company anticipates?

A. The Company considers the proposed AMF deployment plan the most efficient and best approach for Rhode Island customers, the Company, and stakeholders. Extending the deployment period likely will increase costs and delay the benefits. Additionally, as the implementation period lengthens, customers will experience a longer transition period. In reaching this conclusion, the Company relies on the deployment experience by its Pennsylvania and Kentucky affiliates. The Company already has included a Solution Validation step in the implementation plan and a ramp-up period for meter exchanges that builds to the maximum rate of meter exchanges that the full deployment is based upon. The Company considers the Solution Validation and the ramp-up period adequate to work through any issues that may arise, including any issues with the end-to-end data flows from the meters to billing systems.

Q. Does the Company believe it can achieve its proposed timeline?

A. Yes. The Company has confidence in its ability to meet its proposed AMF implementation timeline. PPL has deployed this technology for 1.45 million customers in Pennsylvania and is currently deploying it in Kentucky. Many of the same PPL employees who implemented AMF in Pennsylvania will participate in Rhode Island Energy's implementation. The Company will have the benefit of PPL's experience. As the Division acknowledged in its testimony, "PPL had experience with AMF deployment and operation which would assist RIE in its advancement of AMF and enhance the likelihood of meeting the Company's proposal and some of its benefit propositions." Div. Testimony 9:7-9. The Division also stated that Rhode Island Energy's use of "the same vendors and equipment deployment as has been advanced by PPL . . . should enhance the likelihood of meeting the deployment timeline proposed by RIE." *Id.* 10:4-6.

Q. With respect to the AMF implementation process, the Company intends to conduct "pre-sweeps" to identify challenging meter swaps. OER requests that the Company report on the count of expected challenging meter swaps in advance of the replacement of these meters (OER Request #9). Will the Company agree to this request?

A. Yes.

Q. OER also requests that the Company update its customer communications to provide greater specificity that the expected duration of power interruptions for the meter swaps is under five minutes. (OER Request #9) Will the Company agree to this request?

A. Yes.

Q. OER requests that the Company review its billing process to ensure that billing arrangements associated with DER (especially virtual net metering projects) are carried forward after a customer's meter is replaced. (OER Request #10) Will the Company agree to this request?

A. Yes.

VI. <u>AMF Impact on Safety and Reliability</u>

Q. You testified earlier that the near-real time 15-minute interval data available from the AMF infrastructure provides greater visibility of the electric distribution system. Please explain why this increased visibility is important to enhancing safety and reliability.

A. The AMF infrastructure will feed the 15-minute interval data into the Company's Meter Data Management System ("MDMS") continuously throughout the day. MDMS will then populate that data into the Company's many distribution operations systems, such as the outage management system and advanced distribution management system. MDMS allows this data transfer to occur seamlessly and automatically. Because the Company's electric distribution system operators will now have access to near-real time data, they can understand what is happening on the system in near-real time. This understanding allows the operators to better manage the system in near-real time to keep the system within its voltage and thermal rating limits. These limits are essential to maintaining safe and reliable operations because if they are exceeded, customer and utility equipment can fail, expected lifetime of equipment may decrease, or system stability may be jeopardized. Knowledge of real-time system conditions, including customer demand and circuit/equipment loading, will allow operators to move, transfer, or interrupt load to preserve equipment and infrastructure; prevent damage to customer equipment and wiring, both of which are potential safety hazards to customers and members of the public; and lessen the potential for injury to employees who otherwise would have to perform manual tasks on the electric distribution system.

Q. How does AMF improve the Company's ability to manage power outages?

A. AMF automates outage notification through the Last Gasp feature in the meters. As a result, the Company becomes aware of a problem sooner than it would if it had to wait for customer notifications. This feature, known as "Last Gasp" also provides the Company with a more complete understanding of all the customers affected by the outage because each affected meter will send an automatic notification. As a result, the Company will receive faster and more precise notification of the outage. This in turn will improve the Company's outage detection, dispatch efficiency, and dispatch times. Collectively, this results in an overall improved restoration process, both in terms of improved response time and improved customer experience.

A second aspect of an efficient response to power outages is making sure that when the power comes back on, it comes back on for everyone. Sometimes smaller "nested" outages occur within a larger outage. Currently, the Company may not discover the existence of the nested outage until the Company has repaired the parts of the circuit feeding the nested outage and placed them back in service. By that point, service crews sometimes have left the area and must be redeployed. With AMF, the Company can detect whether customers' power has been restored. The Company can identify any remaining nested outages and address the problem before crews leave the area. This can reduce the amount of time the customers within those "nested" outages would be without power, improving both CAIDI and SAIDI, two of the three major measures of reliability.

Finally, as explained in Section 1.3 of the AMF Business Case, using the AMF information platform for FLISR automation, outages are isolated to small customer blocks using automated distribution switching so that fewer customers experience an outage. AMF information that is used in conjunction with FLISR and ADMS has shown to reduce the frequency of outages.

Q. Are there AMF functionalities that the Company anticipates for the future that will further assist with maintaining safe and reliable operations?

A. Yes. We described some of these functionalities in the AMF Business Case at Bates pages 59-60. These future functionalities include 1) waveform data capture in the meter, which would allow the Company to potentially derive the cause of an electric distribution system issue, for example field equipment problems like cracked insulators; 2) near-real time status maps to combine actual system conditions with electric vehicle charging locations to optimize system use while maintaining reliability; and 3) meter safety alerts enabling the Company to send the affected customer(s) priority alert messages, thereby improving reliability and customer safety.

VII. Implementation of Time-Varying Rates

Q. Both the Division and OER devote significant attention to the issue of TVR. Does the AMF Business Case contain a specific proposal for TVR implementation?

A. No. The Company did, however, consider a range of TVR designs that could be implemented using the proposed AMF solution and analyzed the benefits of TVR for inclusion in the BCA. We discuss TVR with respect to the BCA later on in our larger discussion of the BCA.

Q. When does the AMF Business Case anticipate TVR going into effect?

A. The AMF Functionality Roadmap in Section 6 envisions that the Company's systems would be capable of implementing TVR after AMF meter deployment is complete. The Company currently anticipates meter deployment continuing through the fourth quarter of 2025. TVR would not go into effect until the Company makes a specific TVR proposal and receives approval from the Commission.

Q. Could the Company speed up system readiness to implement TVR?

A. The Company cannot substantially speed up the timeline on which TVR can be implemented. Meter deployment is only one part of what is necessary to implement TVR. The Company also must design, implement, and test billing system and software additions or changes required to support TVR.

Figure 6.1 of the AMF Business Case provides an overview of the AMF Functionality Roadmap and breaks up the timing of these functionalities into six groups. "Enabling TVR" occurs in the last of these six groups. Group five functionalities, which the Company anticipates will be available within 18 months of the start of meter deployment, includes integrating interval meter data to billing systems and establishing the billing system functionality to support TVR billing. Because the functionalities build upon each other, the Company cannot substantially alter the pace at which the functionalities to support TVR become available.

Q. OER suggests that the Commission consider a staggered rollout of TVR as customer subsets are transferred to AMF meters (OER Request #2). In your opinion, is a staggered rollout reasonable?

A. No, a staggered rollout as proposed by OER is not reasonable because it is not practical for the Company to implement TVR on the timeline proposed by OER. Even after a customer receives an AMF meter, the Company cannot switch the customer to TVR (assuming Commission approval) until the supporting IT systems are operational. As discussed above, those systems will not be operational until AMF implementation is complete. Although the Customer Service System ("CSS") that facilitates the billing function includes a simplistic Time-of-Use feature with fixed time blocks, the CSS system as it exists today must be integrated with MDMS and other systems to facilitate successful billing using the new AMF inputs. After that is in place, to realize TVR capability, the system language will need to be added in order to facilitate dynamic rates as contemplated with a future TVR proposal. For these reasons, the Functionality

Roadmap described in Section 6 of the AMF Business Case included TVR after the AMF meters have been fully deployed.

Q. OER also requests that the Commission require the Company to file a proposal to implement TVR by March 31, 2024 (OER Request #1). What is the Company's response to this request?

A. Submission of a TVR proposal by March 31, 2024, is premature and not practical. Although the Company could develop a proposal by March 31, 2024, having the proposal would not accelerate when TVR could go into effect. That cannot occur until the Company has implemented the necessary AMF infrastructure, processes, and systems. Allowing the Company time to develop its proposal as these systems are implemented will result in a more comprehensive and considered proposal.

Q. You take the position that TVR cannot occur until all AMF meters and infrastructure are installed. The Division, however, states that AMF meters are not needed for TVR and that the Company could advance TVR with the existing AMR metering system. Do you agree?

A. No. The Company cannot fully develop and implement TVR with the existing AMR meters. The Company currently collects billing information from the AMR meters with a "drive-by" technology facilitated by ERT. The Company currently has most of its customers using single ERT meters and a small number of customers using triple ERT meters that provide monthly billing readings via the AMR drive-by system. A single ERT can provide only one element of data, and a triple ERT can provide only three elements of data.

Q. Why is it that these existing meters cannot facilitate TVR?

A. TVR requires meters that either have interval reading capability or are pre-programmed with specific time of use ("TOU") channels for a simplistic TOU deployment. The existing AMR meters do not have interval reading capability. Accordingly, they are technically incapable of supporting more complex TVR designs, such as Critical Peak Pricing. Meters that do not have interval reading capability can have the technical capability to support simplistic TOU rates, but to do so, they must have channels capable of capturing multiple measurements to identify the usage during on-peak and off-peak periods. A single ERT meter is incapable of being programmed to have these specific channels because it is only capable of communicating one measurement. In theory, a triple ERT AMR meter could be used to capture readings for on-peak, off-peak, and total kWh to support simplistic TOU rates. In practice, however, Rhode Island Energy's currently installed triple ERT meters already are programmed to bring back total kWh, peak kW, and peak kVA monthly for polyphase customers. Because the channels on these triple ERT meters already are fully utilized for polyphase billing, they do not have any remaining channels available to capture the remaining data required to implement TOU rates. For these reasons, none of the existing AMR meters currently in service could support any kind of TVR structure.

Q. Isn't it true, though, that the Company currently has customers on time-of-use rates?

A. Yes. The Company currently has 1,083 customers enrolled, as of February 2023 in TOU rates. These customers do not use AMR meters. Instead, they use interval meters that the Company installed specially in response to the customers' requests to opt in to TOU rates. These meters are not read using the "drive-by" technology the Company employs for the AMR meters.

Q. Are these simplified types of time-of-use rates that you have described sufficient to manage demand?

A. No. Simplified TOU rates, with fixed blocks of time that represent different rates for on-peak and off-peak energy usage historically have not provided enough of an incentive for customers to change their behavior and shift demand. The lack of effectiveness is multi-pronged. First, the rate differential between on peak and off peak is typically not enough of an incentive to motivate a behavior change. Second, customers have not had near real time information to understand how a change in usage impacts their energy bill. Third, the fixed time blocks represent the system perspective; historically, the technology has not offered the flexibility to dynamically incent customer behavior to achieve a particular outcome. As a result, simplified TOU enrollment is often relatively low, savings may not be as much as customers expect, and the demand remains unchanged.

Q. Could the Company use existing interval meters to implement TVR?

A. Technically, these interval meters have the capability of capturing and storing the data to calculate and apply more complex TVR structures. The logistical challenges of retrieving and processing data from these interval meters, however, make it impractical to fully develop TVR using these interval meters. More specifically, most of the interval meters currently in service must either be read manually, which can take 10-15 minutes per meter, or transmit data over a cellular network. Further, the Company currently has only a very limited number of these interval meters in service. Deploying these interval meters more broadly to develop TVR would amount to essentially a full-scale meter replacement.

Q. What if the Company replaced the existing single ERT meters with triple ERT meters?

A. Hypothetically, the Company could exchange the existing single ERT meters for triple ERT meters. Because these new triple ERT meters would not need to satisfy the polyphase requirements, they would have sufficient channels to implement rudimentary TOU rates. That said, any time TOU rates changed, all the ERT meters would need to be manually adjusted to reflect the new time blocks. Given this effort and the limitation that AMR meters with ERT can deliver only simplified TOU rates, the Company does not consider that doing TOU rates with AMR meters is practical today or beneficial in the future. The Company's response to Data Request DIV 6-10 and Bates pages 190-92 of the AMF Business Case summarize the substantial benefits that come from implementing more sophisticated TVR structures.

VIII. <u>Benefit-Cost Analysis and Docket 4600 Framework</u>

Q. To start off the discussion of the Company's benefit-cost analysis (BCA), can you please provide a summary of the BCA results the Company presented in the AMF Business Case?

A. Yes. In the AMF Business Case, the Company stated that full-scale deployment of AMF will provide benefits of $1,059.3 million Nominal and $729.2 million net present value ("NPV"). The Company estimates the costs as $289.0 million Nominal and $188.0 million NPV. This results in a benefit-cost ratio of 3.9 Nominal and 3.7 NPV.

Q. Does the Division agree with the Company's BCA analysis?

A. No. The Division identified a number of benefits included in the Company's BCA with which the Division disagrees. That said, as we noted at the outset, even with these benefits removed from the BCA, the Division still arrived at a positive benefit-cost ratio. Div. Testimony 33-34.

A. <u>Faster Outage Notification Benefit</u>

Q. The largest benefit that the Division disagrees with is the Faster Outage Notification benefit. Can you begin by clarifying what the Faster Outage Notification benefit refers to?

A. Yes. We initially described the Faster Outage Notification benefit in Attachment H to the AMF Business Case, Benefit Cost Guide Memo (November 2022) as Benefit #22 on page 8. As we explained there, AMF meters automatically notify the utility when the power goes out, rather than relying on the customer to notify the utility. What PPL Electric has found in Pennsylvania is that receiving automatic notification of an outage from the AMF meter resulted in PPL Electric learning about the outage, on average, 22 minutes sooner. We have quantified the benefit that arises from learning of the outage sooner as part of the BCA.

There appears to be some confusion about what the Faster Outage Notification benefit means. The Division's Testimony refers to both a "22 minute outage restoration improvement," Div. Testimony 11:4, and "22-minutes in improvement in outage notification." Div. Testimony 16:6. The Company quantified a "faster notification" benefit, not a "faster outage restoration" benefit. Faster notification and outage restoration time are two distinct concepts. Outage restoration time begins when a utility receives notification of an outage. For utilities with AMR meters, like Rhode Island Energy now, notification occurs when the customer notifies the Company about an outage. For utilities with AMF meters, like PPL Electric, notification occurs when the meter automatically sends notice to the utility of the outage. This automatic notification occurs essentially simultaneously with the outage. Based on data from PPL Electric, the difference between the time an AMF meter sends automatic and the time a customer calls to report an outage is approximately 22 minutes. This benefit was discussed extensively at the February 22, 2023 Technical Conference and the Company responded to numerous data requests about this benefit, including PUC 5-2, PUC 5-8, DIV 1-17, and DIV 3, questions 1-21.

Q. The Division states that assuming notification time will improve by 22 minutes is unrealistic. Instead, the Division proposes that notification time will improve by about 1 minute. How do you respond?

A. First, the 22-minute improvement in notification time is not an assumption; it is based on actual data from PPL Electric. Time stamps showing when the AMF meter automatically notified the utility of the outage and when the first "customer notification" came in to PPL Electric show, on average, that the first customer notification came 22 minutes after the automatic notification from the Last Gasp alarm on the AMF meter. In quantifying the 22-minute improvement in notification time, the Company evaluated one year of PPL Electric outage data that was collected following the Pennsylvania AMI deployment from 2019 through 2020.

After filing the AMF Business Case, the Company reviewed data over a four-year period from 2019-2022 to better understand the longer-term impact of customer behavior on outage notification after AMI was deployed. Over this four-year period, the average improvement in notification time was 25 minutes, which is not substantially different from the result based on looking at one year of data. The Division, on the other hand, has not offered any data to support its assumption of a 1-minute improvement in notification time, or any length of time shorter than 22 minutes.

We provided additional detail regarding the analysis performed in response to the Data Request DIV 3-3. There, we explained that the Company chose the August 2019 through July 2020 timeframe specifically to conduct the BCA analysis with respect to the Faster Outage Notification benefit. The Company selected this timeframe because, in August 2019, PPL Electric had completed most of the meter exchanges and the Last Gasp meter alert functionality was fully implemented. The Company considered this time period the best time period to measure the difference in notification time because customer-initiated call behavior would not have fully adjusted to account for automatic notification. Further, during this same period PPL Electric was able to restore approximately 19 percent of outages based solely on Last Gasp meter alerts, without receiving any customer calls whatsoever. In the two subsequent years, August 2020 through July 2022, that number has increased to approximately 25 percent of the outages being restored based solely on Last Gasp meter alerts.

Second, the Division suggests that the PPL Electric data may be skewed because Pennsylvania customers knew the AMF meters would notify the utility automatically and therefore did not call in until they became frustrated by the response time; however, this is not correct. PPL Electric distinguishes between information-seeking calls and outage notification calls. In determining the 22-minute improvement in notification time, the Company excluded calls seeking information about when power would be restored and raising complaints about outage restoration time. Additionally, if the data were influenced by customer dissatisfaction to the extent the Division suggests, the Company likely would not have observed the same level of consistency in the data over the four-year period referenced above.

Third, outages occur at all times during the day, including at night when customers may be asleep and during the day when the entire household may be away from home. The AMF meter will immediately send an outage notification to the utility regardless of what time of day the outage occurs, but call-in times for customers will likely vary depending on the timing of the outage.

Q. The Division suggests that, given the number of customers per circuit in Rhode Island (approximately 1,300 customers per circuit, according to the Division) and the overall high customer density in the State, there will always be someone who will call in right away when an outage occurs, making the 22-minute improvement unrealistic. Do these factors differentiate Rhode Island from Pennsylvania?

A. No. The outage notification benefit was determined by analyzing the difference in time between the automatic notification from AMF and the time it takes for customers to call the Company to report the outage, on average. The number of customers per circuit and circuit architecture may have some impact; however, this analysis is primarily a measure of customer behavioral response time to report the outage as compared to the time for automatic notification.

Q. The Division recommends that the Commission either remove the 22-minute Faster Outage Notification benefit from the BCA or reduce it to 1 minute. Do you agree?

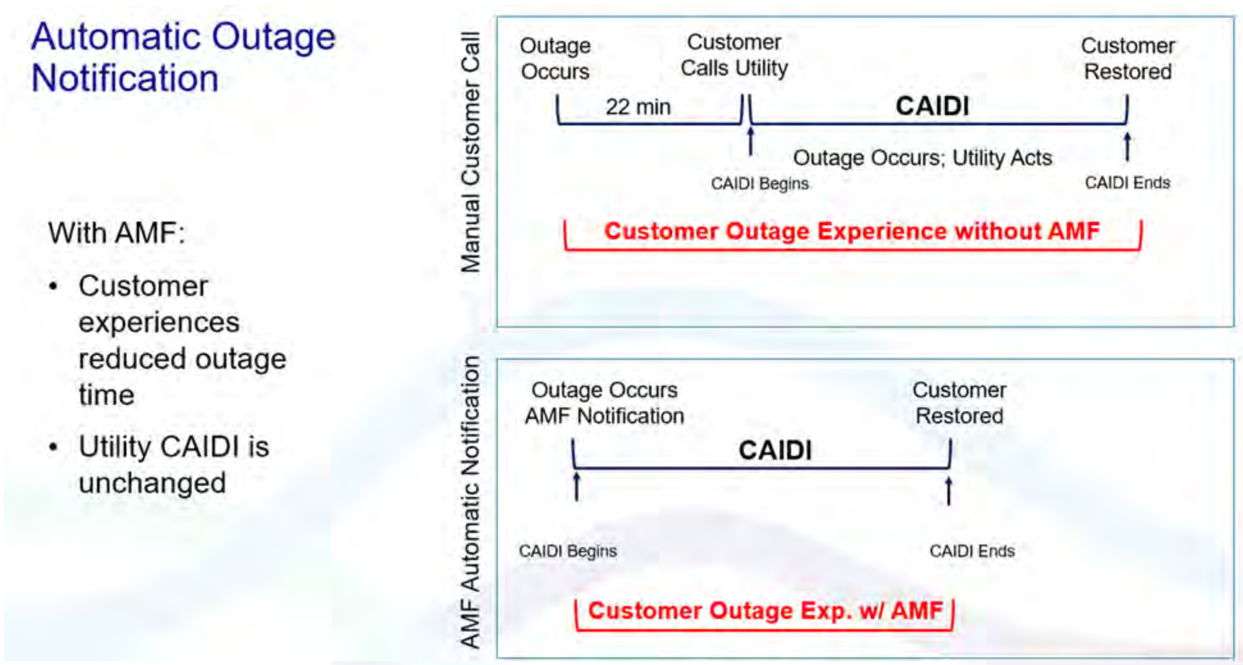
A. No.

Q. The Division suggests in the alternative that, "The 22-minute outage improvement claim should be validated through Commission imposed reliability performance requirements with penalties for failure to achieve specific thresholds." Div. Testimony 17:17-19. What is your response to this recommendation?

A. Such a process would be inappropriate. Reducing the System Average Interruption Frequency Index ("SAIFI") or System Average Interruption Duration Index ("SAIDI") to "validate" the 22-minute faster outage notification benefit, as proposed by the Division, would be inappropriate because faster outage notification has no impact on SAIFI or SAIDI scores. The Division itself acknowledges this when it says, "The SAIDI and [Customer Average Interruption Duration Index ("CAIDI")] times would not be different since the outage time starts as soon as you are aware, therefore the duration is from the time that notification was received to the time of power restoration." Div. Testimony

16:21-23. For SAIFI, SAIDI, and CAIDI, the "clock" only starts when the utility is notified of the outage.

The graph below illustrates these concepts:



Because the 22-minute Faster Outage Notification: (i) occurs before SAIFI, SAIDI, and CAIDI calculations begin, (ii) is not part of the calculation of these metrics, and (iii) does not affect the time it takes the Company to restore power once it becomes aware of an outage, the faster outage notification benefit should not be tied to validation through SAIFI, SAIDI, or CAIDI scores.

Q. The Division also raises concerns about the Company's use of the Interruption Cost Estimate ("ICE") Calculator to determine the value to customers of the faster outage notification benefit. Is the ICE Calculator an appropriate tool to use for this determination?

A. Yes. The ICE calculator is a nationally recognized tool developed by the U.S. Department of Energy specifically to estimate the value of reducing outage times and outage frequency. The ICE tool has been used by many utilities and regulators to determine the value of reliability improvements and reductions in outage times. The Company chose to use this tool because the faster notification provided by AMF meters reduces the outage time experienced by customers. The ICE calculator values were developed by reviewing numerous utility surveys regarding how people value power outages. The ICE calculator values are determined by residential, small commercial and industrial, and large commercial and industrial classes. Details on how the ICE calculator works were provided in response to the Data Request DIV 3-6 and are repeated here:

> "There are three inputs to the ICE calculator when determining with and without improvement reliability values: SAIFI, SAIDI and CAIDI. The instructions show that you must enter values for two of the three index values for each section. Because these 22 minutes impacts the customer experience, the Company decided to

> use an adjusted CAIDI value in the ICE calculator to determine the dollar value impact the 22-minute faster notification would provide as a benefit. Therefore, the Company added the 22-minutes to Rhode Island Energy's CAIDI value to input the data into the ICE calculator. The CAIDI value that was used in the calculation is 68.2, which is the 3-year average CAIDI value for Rhode Island Energy from 2018-2020. This value was input to the 'With Reliability Improvement' CAIDI and 90.2 was input to the 'Without Reliability Improvement' CAIDI. The second input used was SAIFI. The SAIFI used was determined by calculating rolling five-year averages using data from 2005 through 2020 and choosing the lowest value, which was 0.84. This was done to be conservative in the estimates."

Q. Additionally, the Division states that the value generated by the ICE Calculator may be inaccurate because the ICE Calculator value would include value to industrial customers that will not actually materialize from AMF, because Rhode Island Energy's industrial customers already have MV-90 meters that will not be replaced by AMF meters. Do you agree with the Division's concern?

A. No. As the Company explained in response to Data Request DIV 1-12, all customers who have MV-90 meters were removed from the ICE calculation.

Q. Finally, the Division states that the use of a 3.00 percent discount rate for the Faster Outage Notification benefit is inappropriate, and that the Company should have used 6.97 percent. Do you agree?

A. No. The savings from the Faster Outage Notification benefit accrue directly to customers themselves and do not pass through the Company. The 6.97 percent that the Division references is the Company's Post-Tax Weighted Average Cost of Capital (WACC), which the Commission approved during the Company's last distribution rate case (Docket No. 4770). WACC is used to discount benefit dollars that would accrue to the utility, which the utility could then be repurposed into capital expenditures. Applying the WACC to the faster outage notification benefit is not appropriate because the benefit dollars are direct savings to Rhode Island Energy's customers, not Rhode Island Energy. For this reason, the Company applied a societal discount rate as a more appropriate metric.

B. <u>Discount Rate</u>

Q. Let's turn to discussing the discount rate generally. First, what is a discount rate?

A. A discount rate is a factor, expressed as a percentage, used to discount money received in the future to reflect the value that money would have today. The Company's BCA covers a 20-year period, from 2022-2041. Because the analysis is done over a long timeframe and the costs and benefits are spent and/or accrue in different years, discount rates are needed to calculate the NPV of the costs and benefits to have an appropriate comparison of the two sets of numbers.

Q. What discount rates did the Company use in putting together the BCA?

A. As the Division notes in its testimony, the Company used three different discount rates depending on the benefit or cost being discounted to tailor its calculation to the particular benefit or cost at issue.

First, the Company used a discount rate of 6.97 percent for all costs in the BCA and many of the benefits. As we just discussed, the 6.97 percent discount rate is equal to the Company's WACC. The Division agrees with the Company's use of the 6.97 percent discount rate for all costs and many benefits in the BCA.

Second, for benefits derived from the AESC 2021 report, the Company used a discount rate of 2.00 percent. The Division disagrees with the Company's use of a 2.00 percent discount rate for the AESC 2021-report derived benefits.

Finally, as we just discussed, the Company used a 3.00 percent societal discount rate for the Faster Outage Notification benefit, the non-embedded CO2 reductions from vehicle reductions, and the Energy Insights bill savings benefit.

Q. Let's talk about the benefits derived from the AESC 2021 report. First, what is the AESC 2021 report?

A. When we refer to the AESC 2021 report we mean the "Avoided Energy Supply Components in New England: 2021 Report" authored by Synapse Energy Economics, Inc., released on March 15, 2021 and amended on May 14, 2021. The AESC 2021 report was sponsored by a study group representing all of the major electric and gas utilities in New England, as well as energy efficiency program administrators, energy offices, regulators, and administrators. The report was prepared specifically for New England, and it contains values for different areas of New England including Rhode Island. As the executive summary to the report describes, the reports "contains cost streams of marginal energy supply components that can be avoided in future years due to reductions in the use of electricity, natural gas, and other fuels as a result of program-based energy efficiency or other demand-side measures across all six New England states."[1]

Q. How does the AESC 2021 report describe avoided costs?

[1] Synapse Energy Economics, Inc., "Avoided Energy Supply Components in New England: 2021 Report" 1 (Mar. 15, 2021), www.synapse-energy.com/sites/default/files/EASC%202021.pdf

A. The AESC 2021 report describes all avoided costs in 2021 dollars. Because the report brings the future value of all avoided costs back to 2021 dollars, it already has incorporated an inflation rate and societal discount rates to arrive at those 2021 dollar values. Detailed discussion of the derivation of the discount rates used in the AESC report are found in Appendix E: Common Financial Parameters, pages 357-61.

Q. Why did the Company apply a 2.00 percent discount rate to the AESC 2021 report avoided costs?

A. As we described in response to Data Request DIV 1-22, because the AESC 2021 report values were all in "real" dollars (i.e., 2021 dollars), the discount rate needed to match the inflation rate used by the Company in order to tie back to the values reported in the AESC 2021 report. The report used a 2.00 percent inflation rate (p. 357), and the Company also looked at the average U.S. inflation rate for the past 20 years, which was approximately 2.00 percent.

Q. The Division states that the 2.00 percent discount rate is unreasonably low and does not account for all components included within the generally accepted definition of a discount rate. Do you agree?

A. No. Although the Division says that the 2.00 percent discount rate does not account for the time-value of money or the risk of not achieving the expected benefits, these components of a discount rate are already included within the AESC 2021 report's decision to report all future avoided costs in real 2021 dollars. The missing component for converting these 2021 dollars into nominal values was the inflation rate, which the report identified as 2.00 percent.

Additionally, the Company's BCA must tie back to the actual values reported in the AESC 2021 report. This is why the discount rate needed to equal the inflation rate. If the Company applied a different discount rate, as proposed by the Division, the values in the Company's BCA would not tie back to the values in the AESC 2021 report.

Q. The Division suggests that the WACC, adjusted for the 2.00 percent the Company already has included, be applied to the AESC 2021 report avoided costs. Do you agree?

A. No. In addition to the reasons we have already discussed, applying the adjusted WACC to the AESC 2021 report avoided costs is inappropriate because the avoided costs do not accrue to the Company. They accrue to customers. As a general matter, we agree with the Division that when avoided costs accrue to the Company, the Company should use the WACC to discount the costs. In that circumstance, the Company can take those savings and repurpose them into capital investments that will earn the Company's return on equity, which is used to calculate the WACC. For this reason, the Company used the

WACC as the discount rate for avoided costs such as reduced personnel or avoided meter costs.

Here, however, the avoided costs accrue to the customer. Energy cost reductions result in savings to the customer. Avoided transmission and distribution costs also accrue to customers because they are not needed, they will never become part of the Company's rate base and will never appear on a customer's bill. In each instance, because the customer realizes the savings, it is appropriate to apply the AESC 2021 report's societal discount rate.

Q. Why did the Company apply a 3.00 percent discount rate to the faster outage notification benefit, rather than the 2.00 percent discount rate, if the faster outage notification benefit also accrues to the benefit of customers.

A. The faster outage notification benefit is not derived from the AESC 2021 report, nor can it be categorized as an "avoided energy supply components." For these reasons, the Company did not consider it appropriate to apply the 2.00 percent discount rate from the AESC 2021 report to the faster outage notification benefit. Instead, the Company provided a societal discount rate of 3.00 percent. The 3.00 percent rate was based on several factors: 1) the Office of Management & Budget's recommendation of discounting at 3.00 percent and 7.00 for public policy projects; 2) the average inflation rate over the last 20 years, which is approximately 2.0 percent; and, 3) treasury interest rate over the last 20 years, which have ranged from 0 percent to 5.25 percent.

C. <u>Social Cost of Carbon</u>

Q. The Division raises three concerns with the Company's calculation of the social cost of carbon. First, the Division states that the Company has chosen a relatively high value for the social cost of carbon, which increases the value of the expected benefit from AMF in reducing energy usage and demand and therefore carbon emissions. Do you think the Company should use a different cost of carbon?

A. No. The Division stated that the Company derived the social cost of carbon from the AESC 2021 report, which established a range of values from $53 to $870 per short ton of carbon in 2021 dollars. The Company used the values found in the AESC User Interface spreadsheet for the Social Cost of Carbon, which are expressed in $/kWh ($2021). These values range from $143/MWh to $206/MWh, which translates to approximately $330-$450 per short ton ($2021), much less than the top range of $870 per short ton. In addition, Synapse Energy Economics published an addendum to the AESC 2021 report, "AESC 2021 Supplemental Report: Updated Recommendation on the Social Cost of Carbon," that increased the social cost of carbon by more than three times, reflecting the value New England places on reducing carbon emissions. Given the fact that the Company used values that are in the middle of the range, the Company considers the estimate reasonable.

Q. Second, the Division states that if Rhode Island is successful in achieving the mandates for using renewable energy sources, the entire energy system will become less carbon-intensive, and the carbon reduction benefit from each megawatt-hour of avoided energy usage will decrease over time. How do you respond?

A. This observation has merit. As Rhode Island moves towards carbon neutrality, the value of carbon reductions likely will decrease over time. That said, given the current uncertainty of the value of carbon reductions, along with the fact that the Company selected a value within the range that prevailing understanding considers very reasonable, the values calculated by the Company represent valid estimates of the value of carbon reductions.

Q. Third, with respect to the Company's monetized benefit from carbon reduction, which it calculated as the avoided cost of having to pay Renewable Portfolio Standard compliance charges, the Division states that the Company has not considered that these charges will decrease over time as Rhode Island approach net carbon neutrality. How do you respond?

A. This observation also has merit, but the overall value of this benefit is relatively small. Again, given the uncertainty of the value of carbon reductions, the Company's calculated values represent valid estimates.

D. TVR Benefits

Q. As you discussed previously, the Division does not consider AMF meters necessary to implementing TVR and therefore recommends that all TVR benefits be removed from the BCA. Do you agree with this?

A. No, we do not agree with this. As we discussed previously, the existing AMR meters in Rhode Island cannot accommodate time-of-use rates let alone the more sophisticated TVR structures necessary to manage a complex electric distribution system. The AMF meters make available the full complement of TVR structures. Therefore, it is appropriate to include the TVR benefits in the BCA.

Q. The Division also recommends that benefits tied to electric vehicle-charging TVR be removed from the BCA because the Company could administer electric vehicle-charging TVR without AMF meters. Do you agree?

A. No. Although the Company currently operates an electric vehicle-charging TVR program, this program does not use specialized meters but instead pulls data directly from the vehicle charging software. This approach cannot accommodate the sophisticated TVR structures the Company envisions or the anticipated scale of electric-vehicle adoption. Accordingly, including this TVR benefit in the BCA also is appropriate.

Q. Why did the Company separate out electric vehicle-charging TVR?

A. The Company did this for two reasons. First, the Company did this for the purposes of forecasting and calculation. The Company has specific information on electric vehicles loads and how incentives can result in peak reductions and load shifting. Additionally, given the increase in electric vehicles expected to meet the Climate Mandates and RIDEM Draft Regulations, the Company developed a specific forecast for electric vehicles.

Second, the Company wanted to make sure the benefits from whole-house TVR and electric-vehicle charging TVR are both appropriately captured and clearly identified. The Company understands that some households may participate in whole-house TVR, some may participate in electric-vehicle charging TVR, and some may participate in both. Separating the benefits allows the Company to capture and quantify every customer who can benefit without over- or under-counting.

E. Voltage and VAR Optimization ("VVO")/Conservation Voltage Reduction ("CVR") Benefits

Q. The Division states that the BCA should not include VVO/CVR benefits because these benefits resulted from an earlier Infrastructure, Safety and Reliability (ISR) Plan pilot program, and AMF will produce no incremental VVO/CVR benefit. Do you agree with the Division's assessment?

A. No. First, the ISR Plan pilot program deployed VVO/CVR technology on only 10 percent of the Company's feeders. The AMF BCA does not include a benefit for this 10 percent. Instead, it calculates the VVO/CVR benefit based on the remaining 90 percent of feeders.

Second, the VVO/CVR technology deployed in the pilot program was a stand-alone technology that does not offer additional functionalities. The AMF meters, by contrast, can perform the VVO with greater resolution. The previous VVO investments consisted of advanced capacitors and regulators, feeder sensors, and a VVO/CVR control platform that operates on the 45 feeders that have been deployed over the last 3-5 years. In contrast, the AMF meters provide thousands of points available per feeder, creating greater resolution and higher accuracy, which is important as voltage fluctuation and profile uncertainty increases with increases in DER.

Third, the Company included a conservative estimate of VVO/CVR benefits in the BCA, specifically, a 0.5 percent energy and 0.167 percent capacity savings in the AMF Business Case and an additional 2 percent energy savings is attributed to Advanced Field Devices and ADMS in the GMP Business Case. Combining the AMF and GMP VVO energy savings results in 2.5 percent. AMF plays a small, but important role in the overall VVO process, offering near real time voltage data at every customer meter. These VVO savings are relatively conservative compared what is published in VVO/CVR literature (which estimates 1-4 percent savings), the average of what the Company found in its VVO/CVR pilot (which was 1.3-3.5 percent savings), and half of the value assumed by National Grid in Docket No. 5113 for the AMF contribution (which was 1.0 percent for energy and 0.33 percent for capacity savings).

F. <u>BCA Summary</u>

Q. The Division prepared a summary table showing its proposed changes to the BCA. Does the Company have an overall response to the Division's summary table?

A. As we have just described, the Company considers its BCA to reflect a reasonable estimate of the benefits and costs of the full deployment AMF project described in the AMF Business Case, with a few minor spreadsheet corrections identified by the Division. The Company described these benefits and costs in Section 11 of the Business Case. For reference, we include Figure 11.1 from the AMF Business Cases here. The spreadsheet corrections identified by the Division would result in approximately $1.2 million fewer benefits ($2022 NPV).

Figure 11.1: Base Case
Benefits and Costs of Full AMF Deployment ($Nominal and $2022 NPV)

Financial Highlights and Summary ($NPV in Millions)	
As of November 12, 2022	
Business Case Component	**Benefits (20-Year NPV)**
A. Costs	
O&M Expense for AMF System	$ 57.5
New Capital Investment for AMF System	$ 130.5
Total Costs	**$188.0**
B. Benefits	
Utility Benefits	$ 354.7
Direct Customer Benefits	$ 213.2
Societal Benefits	$ 161.2
Total Benefits	$ 729.2
C. Results	
Benefits Less Costs	$ 541.2
Benefit/Cost Ratio	3.9
Payback (Years)	8

Q. The Division supports the Company's use of the same vendors and equipment deployment as PPL has used but also recommends that the Company perform a separate BCA for the meter remote disconnect/reconnect capabilities. Do you agree with this recommendation?

A. No. The Division's recommendation is based on a misconception that removing the remote disconnect/reconnect capabilities will lower the cost of the meters and result in savings. This is not accurate. As the Company indicated in its responses to Data Requests

DIV 4-7, DIV 5-1, DIV 5-2, and DIV 5-3, AMF meters with remote disconnect/reconnect capabilities are less expensive than AMF meters without these features. The Company does not know the source of the Division's information provided in its response to Data Request PUC 1-3. That said, it is the Company's understanding from its vendor that deploying smart meters without remote disconnect/reconnect capabilities has become uncommon in the industry, with more than 90 percent of meters delivered in recent years containing this capability. Because the disconnect/reconnect capabilities have become common practice in the industry, the feature has been incorporated into the standard production line, resulting in lower costs as compared to a similar meter that does not have a disconnect switch. Omitting this feature, by contrast, requires customization.

Thus, because the meters with remote disconnect/reconnect capabilities are at a lower cost and provide greater benefits, there is no need to perform a separate BCA on this functionality.

Q. Do you have any concluding thoughts with respect to the BCA?

A. The Company performed a detailed analysis based on the best available data and information, which demonstrates that the AMF Business Case brings significant value to Rhode Island Energy electric customers. That said, even if the Commission accepts all of the reductions advanced by the Division, the AMF Business Case still has a positive BCA.

IX. Accountability

Q. Both the Division and OER raised concerns about how the Company will be held accountable for achieving the benefits outlined in the AMF Business Case. Did the Company propose any reporting in connection with the AMF Business Case?

A. Yes. Section 14.1 of the AMF Business Case outlines the Company's proposed suite of reporting metrics to provide a transparent assessment of the Company's AMF implementation progress.

Q. Please summarize what the Company has proposed.

A. The Company proposes to file an annual AMF Program Report with the Commission during AMF deployment. Figure 14.1 lists the 19 reporting metrics relating to program implementation, customer engagement, and operations that the Company proposes to include in the annual report. In addition to this annual report, which the Company proposes to file by the end of each calendar year during deployment, the Company proposed to provide a mid-year project status update meeting to the Commission.

Q. Did PPL Electric file annual AMF Program Reports to the Pennsylvania Public Utilities Commission?

A. Yes. PPL Electric filed annual reports in connection with the second-generation AMF project implementation. The Company included example of these annual reports in Attachment B to the AMF Business Case. The Company proposes to customize these reports for the Rhode Island AMF implementation.

Q. Does the Company have a plan to track metrics relating to the Faster Outage Notification benefit?

A. Yes. The Company will have the ability to generate a dataset to track the variance between the timestamp of the "Last Gasp" outage notification and the timestamp for the first customer-initiated notification for the outage in the Outage Management System, using the same approach that PPL Electric has used to determine the 22-minute outage notification benefit.

Q. OER made a number of specific requests for certain metrics to be included in the Company's AMF reporting. First, OER requested that the Company include, as a component of its annual and three-year energy efficiency plans and potential DSM proposals, a discussion of opportunities for energy efficiency and demand response programs to leverage AMF capabilities, with specific reference to devices capable of connecting to the proposed Home Area Network (OER Request #4). Will the Company agree to this request?

A. Yes, the Company will agree to OER's Request No. 4.

Q. OER also requested that the Company include a count of devices connected to the Home Area Network as an additional metric in the annual AMF Program Report (OER Request #5). Will the Company agree to this request?

A. Yes, the Company will agree to OER's Request No. 5. We discuss the Home Area Network in greater detail below.

Q. OER requested that the Company include in the annual AMF Program Report opt-out rates by tenancy (renter vs. owner-occupied), to the extent such data is available (OER Request #12). Will the Company agree to this request?

A. Yes, the Company will agree to OER's Request No. 12, to the extent such data is available.

Q. Finally, OER requested that the Company include in the annual AMF Program Report opt-out rates for customers taking service under the low-income rate (A-60) (OER Request #13). Will the Company agree to this request?

A. Yes, the Company will agree to OER's Request No. 13.

Q. The Division and Mission:data have raised concerns that the Company's Cybersecurity, Data Privacy, and Data Governance Plan lacks sufficient detail and standards. Do you agree with this assessment?

A. No, we do not agree with this assessment of the Company's Cybersecurity, Data Privacy, and Data Governance Plan, which the Company included as Attachment G to the AMF Business Case. The Plan incorporates and relies on a number of industry standards, including those developed by the National Institute of Standards and Technology (NIST), which are restated here for reference: NIST SP 800-53 *"Recommended Security Controls for Federal Information Systems and Organizations;"* NIST SP 800-30 *"Risk Management Guide for Information Technology Systems;"* SP 800-60 *"Guide for Mapping Types of Information and Information Systems to Security Categories"*, and FIPS 199 "*Standards for Security Categorization of Federal Information and Information Systems;*" NISTIR 7628 "*Guidelines for Smart Grid Cybersecurity: Vol. 2, Privacy and Smart Grid;*" NIST SP 800-115 *"Technical Guide to Information*

Security Testing and Assessment." These are discrete, well-vetted standards that are applicable, enforceable, and the current best practices in the industry.

The AMF Business Case also incorporates by reference PPL's detailed standards of conduct. Specifically, the Plan incorporates by reference 11 separate PPL corporate policies relating to the management, protection, and secure availability of the Company's data and information.

Q. The Division suggests that the Company's Cybersecurity, Data Privacy, and Data Governance Plan does not state clearly that customers have the right to access their energy usage data and share it with third parties. What is the Company's position on this?

A. The Company fully supports customers' right to access their energy usage data, share it with third parties whom they authorize to receive it, and to integrate this data with home-enabled devices. The Rhode Island Energy Privacy Notice, which is published on Rhode Island Energy's website at www.rienergy.com/Privacy-Policy, sets forth the Company's position on consumer protections.

Q. OER requests that the Company's proposed solar marketplace not include links or referrals to specific installers, developers, or projects (OER Request #8). How does the Company respond to this request?

A. The Solar Marketplace functionality the Company proposes to include in the Customer Portal is intended as a research tool for customers to gather information, including contact information for local installers, before filling out a rooftop solar interconnection application. The Solar Marketplace would provide vendor-neutral advice to customers and would not provide recommendations on specific installers. Although the Company does propose that the Solar Marketplace would include a list of potential installers based on the customer's zip code, the Company does not intend to perform any prescreening of the potential installers other than determining their qualifications to perform the work. Customers would have complete discretion and choice to determine how, or if, to proceed.

Q. OER requests that the Company update its interconnection study process to consider the timing of load and DER output, as illustrated in the Company's response to OER 1-13 (OER Request #11). How does the Company respond to this request?

A. As the Company stated in response to Data Request OER 1-13(b), the Company does not consider that any changes to its interconnection process will be necessary because the AMF meters will provide better information that will replace the assumptions the Company must make in the absence of such data.

X. <u>Topics for Future Discussion and Development</u>

Q. Are there additional topics raised in the intervenors' testimony that you have not discussed?

A. Yes, there are a handful of topics, primarily in Mission:data's testimony, that we have not yet discussed. These topics relate generally to the issue of energy data portability and specifically to the Company's proposals for Green Button Connect and Home Area Network and what Mission:data refers to as Distributed Intelligence.

Q. In your opinion, does the Commission need to address these issues in connection with this docket?

A. No, in our opinion the Commission does not need to address these issues in connection with this docket, and it would be premature to do so.

Q. Why?

A. There are several reasons. First, the Commission must first decide whether to approve the AMF Business Case and greenlight the implementation of AMF before these issues become material. Second, the Company cannot predict now what functionalities, technologies, or software products will be available at the time AMF deployment is complete. The Company cannot develop fully detailed policies and processes regarding how Green Button Connect and the Home Area Network will work until the Company knows what technologies are available and how they will be used. Third, as OER suggests, it will be most constructive to assemble a working group to develop standards and requirements pursuant to which service providers can access customer data. (See OER Request #6 and Request #7). The Company agrees that many stakeholders have an interest in how customer data is used and what kinds of applications may operate on the proposed AMF meters. The Company envisions that the Division, based on its statutory and regulatory authority, will have a role in making these determinations through the proper proceedings. The Company therefore considers it premature for the Commission to make determinations on these issues raised by Mission:data.

Q. If the Commission approves the AMF meters and related infrastructure and technology proposed in the AMF Business Case, will this decision foreclose the later adoption of any of the capabilities proposed by Mission:data?

A. No. The AMF meters and related infrastructure and technology the Company has proposed will be fully capable of deploying any of the capabilities proposed by Mission:data in the future. The Commission would not be foreclosing any future capabilities by adopting the Company's AMF proposal set forth in the AMF Business Case.

Q. Mission:Data has proposed a number of additional reporting metrics for Green Button Connect, Home Area Network, and Distributed Intelligence meters. How does the Company respond to these recommendations?

A. It is premature to define these metrics before the necessary infrastructure has been installed. The AMF infrastructure must be installed before future functionality relating to pairing, uploading applications, or third-party usage associated with future distributed intelligence functionality can be defined, let alone monitored and measured. As these advancements become available, the Company will identify appropriate metrics in consultation with stakeholder, perhaps as part of the working group suggested by OER.

The Company does not agree, however, with Mission:Data's recommendation to establish varying reporting frequencies metrics as compared with the overall AMF Program Report. The Company maintains that all reporting metrics should be provided together and reported in an agreed-upon, annual cycle, with mid-year updates during the implementation phase. This is sufficient to track and monitor the Company's activities, without imposing an undue administrative burden on it or the Commission.

A. <u>Green Button Connect</u>

Q. Let's discuss some of the specific concerns raised by Mission:data. Mission:Data states that the Company's Green Button Connect ("GBC") plan is inadequate because it does not establish a complete set of software requirements up front, such as identifying which specific Function Blocks the Company will support when AMF is fully operational. Can the Company provide the level of specificity that Mission:Data has recommended?

A. No. The Company cannot predict what Function Blocks will be most advantageous to Rhode Island customers, or what changes may occur in data privacy and governance standards between the filing of this AMF Business Case and the date on which AMF becomes fully operational in Rhode Island. The Company is committed to giving customers full control over where their data goes and whether and to what extent they choose to share it with a third party through GBC. The Company cannot, however, identify exactly what data or technology will be available before AMF is in place.

Q. Mission:data's other recommendations regarding GBC center on the types of datasets, certifications, and terms and conditions that should apply to or be available from GBC. How do you respond to these recommendations?

A. As we stated previously, these requests are premature. The Commission must determine whether to approve AMF implementation before any of these issues become material. Further, the Company intends the Cybersecurity, Data Privacy and Data Governance Plan to serve as the governing document with respect to how the Company will handle customer data developed from AMF implementation. To the extent additional policies or procedures become necessary, the Cybersecurity, Data Privacy and Data Governance Plan establishes a procedure for amendment or additions. Stakeholders will have involvement in this process.

B. <u>Home Area Network</u>

Q. Let's talk next about the Home Area Network ("HAN"). Mission:data's HAN recommendations rely heavily on the IEEE 2030.5 standard. Specifically, Mission:data has recommended that as long as a HAN device complies with the IEEE 2030.5 standard, the Company should be obligated to treat all device connection requests from customers equally. Do you agree with this recommendation?

A. No. It is inappropriate to require the Company to treat all device connection requests from customers equally based solely on the device's compliance with the IEEE 2030.5 standard. The IEEE 2030.5 standard focuses on "exchanging energy information and controlling energy-consuming devices or appliances," not on cybersecurity or data privacy. Thus, while the Company agrees that a customer's experience using the HAN should be the same, with no preferential treatment based on the type of device used, this consideration cannot trump the importance of properly securing customer data and accounting for cybersecurity considerations. Any device connecting to the AMF meters must meet cybersecurity, privacy and other criteria establishing compliance with the Company's Cybersecurity, Data Privacy, and Data Governance Plan—not just the IEEE 2030.5 standard.

Q. Mission:data also has recommended that the Company be required to commit to a bring your own device ("BYOD") model. How does the Company respond recommendation?

A. As we explained, the BYOD model effectively requires the Company to treat all requests for connection equally, so long as the requesting device meets the IEEE 2030.5 standard. Because that standard does not consider cybersecurity or data privacy, the BYOD model risks creating customer data vulnerabilities. Accordingly, the Company will not commit to any model that has the potential to systematically compromise customer data or introduce cybersecurity threats. Rather, the Company is committed to supporting the data access channels identified in the AMF Business Case.

Q. OER has requested that the Company submit objective criteria to evaluate devices that could access the HAN and establish a process for identifying eligible devices (OER Request #3). How does the Company respond to this request?

A. The Company anticipates that these types of criteria will be developed through the working group process that OER has proposed. Any such criteria must promote fair treatment, evolving technologies, and the Company's Cybersecurity, Data Privacy and Data Governance Plan.

Q. Mission:data has recommended that the Commission postpone cost recovery for HAN hardware and software until the HAN functionality is usable by customers. Mission:data further recommends that the Commission hire an independent consultant to conduct a fair-value assessment of these components for each meter type. How does the Company respond to this recommendation?

A. The Company has explained that it does not seek cost recovery for any asset until that asset is placed into service and used and useful for customers. The Company intends to follow its regular process with respect to HAN-related costs. If the Commission approves the Company's request for an AMF Factor, the Commission and Division will have an opportunity to review the costs incurred and their reasonableness at the time of the Company's semi-annual AMF Factor filings.

Q. Mission:Data has recommended that the Company be required to recertify its compliance with IEEE 2030.5 standard periodically. Is this necessary?

A. No. The IEEE 2030.5 standard is part of the grid edge card so applications that operate on the AMF meter can utilize IEEE 2030.5 to communicate with other IEEE 2030.5 devices. The grid edge marketplace is still evolving, and the related standards could change. The Company considers it premature and too narrow to commit to a recertification process that exists today. The Company is committed to evolving with the marketplace and making adjustments as necessary in consultation with relevant stakeholders.

Q. Finally, Mission:data has made certain recommendations regarding the ability to transfer data. How does the Company respond to these recommendations?

A. At a high level, the meters and related infrastructure and technology that the Company has proposed will allow for customers to authorize the transfer of their data. The topic of data transfer falls within the Company's Cybersecurity, Data Privacy and Data Governance Plan, and the Company anticipates that any necessary protocols will be developed. The Company considers it premature to commit to any particular data transfer process at this time.

C. Distributed Intelligence

Q. Mission:data has raised concerns that the Company may not provide equal access to customer data gathered by Distributed Intelligence ("DI")-capable meters. How does the Company respond?

A. Mission:Data has raised a number of hypothetical concerns but has not pointed to any specific evidence that the Company may refuse third-party access to that data in an anti-competitive manner. The Company's Cybersecurity, Data Privacy, and Data Governance Plan outlines specifically how the Company will handle customer data. Further, the Company does not sell customer data.

As explained previously, the Company is focused on ensuring that third-party data recipients meet rigorous cybersecurity and data privacy standards as outlined in the Cybersecurity, Data Privacy, and Data Governance Plan. In turn, the Plan adheres to fair competition principles, including fair, reasonable, and non-discriminatory terms of connection; information symmetry; user experience symmetry; anti-blocking; and ensuring that customer data is owned by customers. To the extent that specific definitions or governance policies are needed to facilitate and manage the accessibility of DI-generated data, the Company will define those terms and policies after the approval of the AMF Business Case.

XI. <u>Conclusion</u>

Q. Please summarize the areas of agreement among the parties.

A. The parties all support the implementation of AMF in Rhode Island and agree that implementation should commence expeditiously. The Company's AMF Business Case presents a positive BCA and will deliver benefits to Rhode Island customers. Further, the parties agree that AMF implementation should make available 15-minute interval usage and voltage data in near-real time. Additionally, the Division agrees with the Company's selection of Landis+Gyr to provide meters and related technology and services for AMF implementation.

Importantly, the parties also agree that AMF implementation is important for achieving the State's climate goals.

Q. Please summarize the areas of disagreement among the parties.

A. There are areas of disagreement, although these areas are not as significant as the areas of agreement. Many of the areas of disagreement, particularly with respect to future functionalities, can be addressed at a later time. Proceeding with the AMF implementation proposed in the AMF Business Case will not cut off the possible future functionalities some of the parties want the Commission to consider.

Q. Given this, what is the Company's request of the Commission?

A. The Company requests that the Commission approve the Company's proposed AMF implementation plan as set forth in the AMF Business Case.

Q. Does this conclude your testimony?

A. Yes.