The Narragansett Electric Company
d/b/a Rhode Island Energy

Advanced Metering Functionality Business Case

Joint Direct Testimony of:
William F. Watson, PhD and
Robin W. Blanton, PE

April 28, 2023

RIPUC Docket No. 22-49-EL

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
Gregory L. Booth, PLLC
on behalf of
The Rhode Island Division of Public Utilities and Carriers

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

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

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JOINT DIRECT TESTIMONY

I. INTRODUCTION AND QUALIFICATIONS

William F. Watson, PhD

Q. PLEASE STATE YOUR NAME AND THE BUSINESS ADDRESS OF YOUR EMPLOYER.

A. My name is William Franklin Watson. I am Principal and owner of Econalytics, LLC, a Virginia consulting firm located at 1603 Logwood Circle, Richmond, Virginia 23238, and am contracting with and filing testimony under Gregory L. Booth, PLLC ("Booth, PLLC"), mailing address 14660 Falls of Neuse Road, Suite 149-110, Raleigh, North Carolina 27614.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A. I am testifying on behalf of the Rhode Island Division of Public Utilities and Carriers (“Division”).

Q. WOULD YOU PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND?

A. I have a B.A. in Economics, a Master of Economics, and a PhD degree in Economics with a Statistics minor, all from North Carolina State University. In addition to a broad and general background in economics, the areas in which I concentrated for my doctoral degree were industrial organization, regulation and econometrics. My PhD research and dissertation was an analysis of the characteristics of energy substitution in United States manufacturing, a topic that has taken on new relevance in today’s push to find alternatives to carbon-based fuels.

Q. PLEASE STATE YOUR EXPERIENCE AND BACKGROUND.

A. I have more than 40 years of experience in the field of utility regulation performing a wide array of services. My first employment out of graduate school was in 1977 as the departmental economist with the North Carolina Attorney General's office, which ultimately led to a position of Director of the Economic Research Division for the Public Staff of the North Carolina Utilities Commission, an entity formed to focus on the consumer in the regulation of utilities in North Carolina. There I led a team of economists in developing cost-of-capital, load forecasting, rates, and cost-of-service analysis on behalf of North Carolina electric, natural gas, telecommunications and water and sewer utilities, providing testimony on all these topics before the NC Utilities Commission and the Federal Energy Regulatory Commission in contested hearings.

From 1981 to 1999, I worked with ElectriCities of North Carolina, a corporation of municipally owned electric systems, where I held different positions at the middle and senior management level. My experience with ElectriCities centered on the generation and transmission entities for forty-three locally owned municipal power distribution entities, and included developing wholesale rates, forecasting loads and budgeting, including long-term strategic planning, negotiating power purchase agreements with power suppliers on behalf of the municipalities, overall oversight of approximately 1400 megawatts of nuclear and coal-fired generation of which the Power Agencies had joint ownership, and development of plans for the building and operation of combustion turbine generation. I also developed and implemented a retail rate assistance program used by many municipal electric utilities. As Director of Power Supply, I managed a staff with engineering and accounting backgrounds. As Director of Strategic Planning, I oversaw the transition of the North Carolina Power Agencies and the municipal distribution systems into the world of electric generation deregulation and served as the Chief Budget Officer and Planner for the organization.

From 1999 to 2006, I worked with North Carolina Electric Membership Corporation ("NCEMC"), the generation and transmission entity responsible for arranging, acquiring, operating and financing the power supply needs of twenty-three distribution electric cooperative entities in North Carolina. My work focus was on strategic planning and power supply. My experience included statistical analysis for wholesale rates, strategic plan development, scenario planning, acquisition analysis and pricing, long-term rate projections and working with the North Carolina Legislative Study Commission on the deregulation of the electric industry in North Carolina. As the dust began to settle on electric deregulation in North Carolina, my experience shifted to include statistical analysis and hourly load forecasting for power supply budgets, developing strategies to optimize Financial Transmission Rights revenue for NCEMC's participation in the PJM Interconnection, working with renewable energy suppliers and individual electric distribution cooperatives to develop mutually beneficial power purchase agreements, and liaison with the North Carolina Utilities Commission which included overall responsibility for the preparation of the NCEMC Annual Integrated Resource Plan.

From 2006 to 2009, I worked with PowerServices, Inc., a privately held electric engineering and management consulting firm providing services to a range of small- to large-sized electric utilities for municipal, cooperative, investor-owned, and industrial electric power systems. My experience included analysis of cost-benefits of various projects, cost-of-service studies with rate design and recommendations, long-range planning for small to medium sized utilities, analysis of trends in the electric utility industry, review of regulatory filings and analysis of loss, and assessment of system valuation for acquisitions.

From 2009 to 2018, I worked with Old Dominion Electric Cooperative, a Virginia-based generation and transmission entity responsible for arranging, acquiring, operating and financing the power supply needs of eleven electric cooperative distribution entities in Virginia, Maryland and Delaware. My experience included ensuring that Old Dominion Electric Cooperative and its 11 electric distribution cooperatives met all federally mandated requirements to provide reliable and secure electric service to their consumers and as an integrated part of the national electric grid with entities such as the PJM interconnection. This includes assisting in the development of regulatory standards to meet energy policy requirements adopted by the United States Congress and under the supervision and enforcement of the North American Electric Reliability Corporation ('NERC").

In 2018, I formed Econalytics, LLC, a consulting firm specializing in working with utilities in the application of the principles of economic analysis to meet existing operational challenges and to develop and implement strategic plans to operate successfully in the future environment.

In addition, I have held adjunct faculty positions at both North Carolina State University in Raleigh, NC and Virginia Commonwealth University in Richmond, VA, where I have taught a range of economics and statistics courses to undergraduate and graduate students. While it has not been a focus of my employment, I have published papers on competition and monopoly, and on the effectiveness of regulatory standards.

Q. WHAT EXPERIENCE DO YOU HAVE IN THE APPLICATION OF BENEFIT-COST ANALYSIS ("BCA")?

A. In the corporate positions that I have held, I have applied benefit-cost analysis a multitude of times. Some examples include analyzing the benefits and costs of multiple load control strategies constrained by excess capacity under uncertainty, analyzing benefits and costs of different strategies of stranded cost recovery from deregulation of electric generation, analyzing positions in power supply negotiations and lawsuit settlements, and various studies of benefits and costs of distributed generation. I additionally taught the application of benefit-cost analysis in my foundations of economics classes to undergraduate engineering students at Virginia Commonwealth University.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT BEFORE REGULATORY COMMISSIONS AND POLICY-MAKING BODIES?

A. Yes. I have testified before the North Carolina Utilities Commission, the North Carolina General Assembly, and the Federal Energy Regulatory Commission. I have also testified before the Virginia State Corporation Commission and the Connecticut Public Utilities Regulatory Authority.

<u>Robin W. Blanton, PE</u>

Q. PLEASE STATE YOUR NAME AND THE BUSINESS ADDRESS OF YOUR EMPLOYER.

A. My name is Robin Wayne Blanton. I am a sole proprietor located at 1824 Yamacraw Drive, Knightdale, NC 27545, and am contracting with and filing testimony under Gregory L. Booth, PLLC ("Booth, PLLC"), mailing address 14660 Falls of Neuse Road, Suite 149-110, Raleigh, North Carolina 27614.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A. I am testifying on behalf of the Rhode Island Division of Public Utilities and Carriers ("Division").

Q. WOULD YOU PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND?

A. I have a B.S. in Electrical Engineering from Clemson University, and am a Registered Professional Engineer in 11 states. In addition, I have taken Continuing Education Courses to maintain my professional engineer licenses in each of these states, as well as attending numerous industry conferences and training seminars as provided by vendors and software companies.

Q. PLEASE STATE YOUR EXPERIENCE AND BACKGROUND.

A. I have more than 40 years of experience in the field of utility electric engineering and operations, and have performed a wide array of services. I currently work as a consulting engineer providing engineering services in many states along the eastern United States to electric utilities to include investor-owned utilities, electric cooperatives, and municipalities together with regulatory clients. My electrical engineering consulting work has included transmission, substation and distribution engineering, design, project management and field services. I have performed numerous long-and short-range planning studies, protective coordination studies, analysis of ISR Plans, and benefit cost analysis. I have also investigated utility equipment failure, and personal injury and property damage matters. I have provided consulting services to electric utilities on AMI Systems and benefit analysis of these systems.

I have worked for electric utilities both nationally and internationally. While employed by an electric utility in Virginia, which had acquired a portion of an investor-owned utility system, I provided the engineering analysis, design, procurement and project management for the installation of a Mesh Network AMI system, which is similar to the AMF system currently proposed by RIE in its Business Case. I managed 5 substation rebuild projects which involved rebuilding a ring bus in two of these substations along with rebuilding a single circuit transmission line with a double circuit transmission line. I additionally was responsible for the coordination of the distribution system and assisted with outage restoration, and the grid modernization expansion including self-healing circuits.

I worked for National Rural Electric Cooperative Association ("NRECA") International on projects in Pakistan to improve reliability at the 9 distribution companies in the country, installing an AMI system that used cellular service as the backhaul method, and provided training to the utility employees to improve safety.

I was employed at an electric utility in North Carolina as Manager of Engineering and was responsible for all engineering and construction projects. Part of my responsibilities were the installation of a Landis & Gyr AMI System, completing Construction Work Plans and Long-Range Plans, and coordination studies, and overseeing substation and transmission line construction and repairs, outage restoration, distribution line design, and dispatch operations. I was also responsible for the cost-benefit analysis of an AMI system, and then the installation, implementation, and integration of the system with the billing, outage management, and engineering analysis software.

Before that, I was employed at a major electric municipal utility in North Carolina as the Utility Director. In this role, I was responsible for the complete engineering, construction, operation, and planning of the electric system.

I then continued to provide electric engineering design and management services to many types of electric utilities with several electric engineering consulting firms.

My over 40 years of experience includes transitioning metering systems from electromechanical meters to AMR and solid-state meters and then to the most advanced AMI/AMF metering systems. This has included as an employee at multiple electric utilities as well as performing all aspects of engineering and implementation from procurement analysis, specifications, managing field installations, troubleshooting meter and communication system deficiencies and failures and integrating the metering data through outage management systems, billing and engineering software and utilization for engineering models and outage management and restoration activities. I was hands on with each aspect of the system implementation at multiple utilities.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT BEFORE REGULATORY COMMISSIONS AND POLICY-MAKING BODIES?

A. No, I have not. My regulatory experience is based on my years of providing electric engineering evaluation, analysis, and research assistance in various regulatory matters on behalf of Mr. Gregory L. Booth for regulatory entities in North Carolina, Virginia, Delaware, Rhode Island, and Connecticut.

II. PURPOSE OF JOINT TESTIMONY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. The purpose of this testimony is to delineate the Division's position on the Advanced Metering Functionality ("AMF") Business Case and the deployment of AMF technology to replace the existing Rhode Island Energy ("RIE" or "Company") metering system. This testimony is intended to outline areas of support and areas of concern, and to include recommendations which are intended to protect the ratepayer. The Division will also specifically enumerate those portions of the Company's testimony and Business Case for which the Division has disagreement or which need adjustment or clarification.

III. AMF BUSINESS CASE EVALUATION PROCESS

Q. WOULD YOU BRIEFLY OUTLINE THE PROCESS WHICH LEADS TO THE DIVISION'S COMMENTS, RECOMMENDATIONS AND SUPPORT FOR THE AMF DEPLOYMENT?

A. Yes. We will first start with a broader overview, and then provide details. During our conferences with the Division and the Company, it became very evident that while the PPL philosophy was different than National Grid (partially discussed on pages 38 and 39 of Walnock and Reder 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. In the review of the Company's filed testimony and Business Case, we evaluated the AMF deployment, engineering and operation issues and the Business Case in six distinct areas of evaluation. These are: 1) the need to replace an aged metering plant and rapidly replace metering technology; 2) the engineering, procurement and advancement decisions and assumptions; 3) the evaluation of the BCA and its assumptions; 4) the revenue requirement, AMF factor and mechanisms to protect the ratepayer from overly aggressive assumptions and promises; 5) data governance assessment; and 6) load and distributed energy resources ("DER") projects for interconnection on the distribution system.

Q. YOU STATED THAT DURING THE CONFERENCES AND IN THE COMPANY'S FILING IT WAS EVIDENT THE PPL AND RIE PHILOSOPHY IS DIFFERENT THAN THE EARLIER NATIONAL GRID APPROACH. WOULD YOU ELABORATE?

A. Certainly. Early in this process, RIE indicated that PPL had already installed AMF and was well along with its integration, including into the advanced distribution management system ("ADMS"). PPL is providing its ADMS to RIE and that will be advanced much more quickly than would have occurred under National Grid. The RIE timeline is 3.5 years, whereas National Grid presented a much longer timeline spanning over 5 years. Additionally, RIE may be using the same vendors and equipment deployment as has been advanced by PPL. Each of these differences in philosophy should enhance the likelihood of meeting the deployment timeline proposed by RIE.

Q. WOULD YOU PROVIDE AN OVERVIEW OF YOUR CONCERNS AND HOW YOU HAVE ORGANIZED YOUR TESTIMONY TO PRESENT YOUR POSITION?

A. Certainly. While the Division supports the installation of AMF, it will provide the Commission timeline options which will mitigate short term rate impacts. We are presenting areas of concern with the claimed benefits of AMF by the Company in the Benefit-Cost Analysis. Our testimony will first present the engineering, operation and deployment areas of disagreement or which require further clarification to establish a more complete regulatory record. We then address the BCA and the areas we find that need adjustment. We also outline areas of potential protection for the ratepayer. Lastly, we have summarized our position and delineated our recommendations.

IV. ENGINEERING, OPERATION AND DEPLOYMENT ANALYSIS

Q. PLEASE SUMMARIZE THE ENGINEERING AND OPERATION ISSUES THAT ARE ADDRESSED IN THIS TESTIMONY.

A. We are not addressing every engineering detail since most are a function of implementation of any AMF system and the overall deployment process. The items specifically being addressed include: 1) The necessity for the replacement of the existing metering infrastructure; 2) the timeline proposed and required; 3) the AMF system manufacturer selected and the deployment scheme including the Mesh Network and web based utilization; 4) the selection of all residential meters having a disconnect means; 5) the Business Case assumption of a 22 minute outage restoration improvement resulting from the AMF system; 6) unaccounted for new system deployment difficulties and impacts; 7) time varying rate ("TVR") assumptions; and 8) overall AMF system transition.

Q. YOU HAVE LED THE TRANSITION FROM AN AMR METERING SYSTEM TO AN AMF METERING SYSTEM AT MULTIPLE UTILITIES. DO YOU AGREE WITH THE COMPANY'S CHARACTERIZATION OF THE URGENCY OF IMPLEMENTATION?

A. We do not agree with the level of urgency placed on the AMF system implementation by the Company for several reasons.

Q. WHAT ARE THE REASONS YOU DISAGREE WITH THE LEVEL OF URGENCY?

A. We agree the existing meters are nearing the end of their depreciated life. This, however, is an accounting life function and not the real operational life. The industry continues to support automatic meter reading ("AMR") systems and will for some time due to the fact there remain many systems in place at electric utilities, including in New England (such as Eversource). Aging does not mean nonfunctional or extremely short lived. Additionally, AMR systems allow for customer choice, TVR, and other functionality that does not degrade reliability or safety. Additionally, there is no evidence that the use of AMR has resulted in adverse operations associated with DER. The Walnock and Reder witness testimony on page 12, lines 1 through 3, overstates the urgency and that AMF somehow would provide safe and reliable service which has not been provided over the years to the Rhode Island customers.

Q. HAVE YOU CONFIRMED THE AMR METER AND EQUIPMENT CURRENTLY IN PLACE REMAINS SUPPORTED BY THE MANUFACTURER?

A. Yes. We have discussed the level of support with the manufacturer and they indicated they still manufacture the meters and equipment and will be supporting this technology for some time into the future. The industry will be supporting AMR technology for no less than ten years considering the volume of AMR equipment currently in service.

Q. IS THE DIVISION SUGGESTING A DEFERRAL IN IMPLEMENTATION OF AMF?

A. No. While the Division supports the Company's proposed timeline, we feel it is essential for the Commission to understand that AMF deployment is not as urgent as characterized by the Company. Our opinion is that safety and reliability will not be compromised if AMF implementation is slower than proposed. It is also our opinion that DER integration and transition toward the State Act on Climate goals will not suffer if AMF implementation does not meet the Company's timeline. AMF is the right technology, and it is the right time to invest in AMF. However, the implementation timeline and full incorporation of all functionalities could be spread out over a longer period if the Commission deemed it appropriate to lessen the short-term rate impact. Furthermore, the first step is the replacement of the meter itself and the completion of the communication system for AMF. The other functionalities such as Load Disaggregation, Carbon Footprint Calculator, and Grid Edge Computing can follow years later and not compromise safety and reliability.

Q. ARE THERE CONCERNS THE COMMISSION SHOULD BE AWARE OF ASSOCIATED WITH THE METERING SYSTEM VENDOR SELECTED AND

THE TYPE OF DESIGN AND DEPLOYMENT? WHAT ARE THOSE CONCERNS?

A. The Company is proceeding with a sole source vendor and is not proceeding through the customary process of solicitation in the open marketplace, nor is it performing the customary engineering design analysis for system selection and optimization. The Company has assumed that using the PPL selected AMF system vendor with a mesh network and web-based system is the most appropriate and advantageous manner to proceed. Absent a detailed analysis for Rhode Island, it can neither be disputed nor confirmed that this assumption is accurate and is the most economical direction for Rhode Island. 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, however, the Commission should recognize there is no study or detailed analysis to support that hypothesis.

Q. DOES THE DIVISION RECOMMEND A DETAILED STUDY BE COMPLETED BEFORE THE COMPANY PROCEEDS WITH THE PROPOSED AMF IMPLEMENTATION?

A. No, the Division does not believe a study of vendor options is necessary. The level of assumptions that may drive a different vendor selection or system design would always be questioned and could never be verified to be accurate years or decades from now with PPL operating one system and RIE operating a different system. While using the same vendor may not be the most economical decision in the short term, 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. The Division does recommend that a separate BCA and analysis of the utilization of meter disconnect technology be completed.

Q. WHY DOES THE DIVISION RECOMMEND A SEPARATE BCA AND ANALYSIS OF THE UTILIZATION OF METER DISCONNECT TECHNOLOGY?

A. It will cost at least an additional $16,000,000, at $30 or more per meter, to have remote disconnect and reconnect technology on each residential meter. This technology is not currently available for larger commercial and industrial applications since the disconnect means is not offered on three-phase meters and current transformer type meter installations. The existing tariffs and restrictions on customer disconnects combined with the relatively low number of disconnects implemented makes it very expensive to install every meter with this capability when very few would be used for this function. Furthermore, the Company charges the customer for disconnect/reconnect services, which means the customer responsible for the disconnect pays the cost rather than a $16,000,000 cost to be imposed on every customer when the vast majority are never disconnected. Also, the Company is already collecting the cost of disconnect and reconnect operation and maintenance in its rates. Therefore, customers paying for this technology would be paying twice for the same service and at a much higher cost than is now being incurred. Additionally, the typical utility business practice for customer changes at a residence is to just take final meter readings as move-in/out residential occupancy changes as opposed to disconnecting service and then reconnecting the service. This is aligned with RIE's current practices.

Q. THE COMPANY HAS ASSUMED A 22 MINUTE OUTAGE RESTORATION TIME IMPROVEMENT RESULTING FROM THE AMF SYSTEM. IS THAT A REALISTIC ASSUMPTION?

A. Our experience and knowledge of outage restoration on systems prior to and after AMF implementation does not support a significant improvement in outage restoration time. We disagree with the 22 minutes characterized by the Company.

Q. EXPLAIN WHY YOU DISAGREE WITH THE 22 MINUTE OUTAGE RESTORATION IMPROVEMENT CHARACTERIZED BY THE COMPANY.

A. The Company only made a vague reference as to how it estimates the 22-minute outage restoration improvement in its filing. The Company's responses to a series of Division data requests provides some additional insight. There is no statistical analysis of circuits comparable to RIE and the overall operations of the system. We will address the Company's response to data requests later in this testimony. Our experience with other utilities, including direct management of system metering, outage management system and outage restoration at three utilities indicate only a very small marginal improvement, and only on circuits with 10 or fewer customers. The improvement of beyond one minute only occurred when a long single-phase lateral serving 3 to 10 customers was out of service. In those instances you may only have 1 or so customers at home and thus only have one call go through the outage management system to initiate the troubleshooting process. When larger three-phase line outages occurred, there would be numerous outage calls and the Outage Management System ("OMS") would have a service person or crew dispatched immediately. Thus, AMF would only produce a 30 to 60 second improvement in notification. RIE has 524,677[1]customers on 400 circuits which is an average of over 1,300 customers per circuit. Based upon the small geographic footprint of RIE and the customer density, our experience with numerous utilities would indicate that AMF contributes an

[1] Book 2 of 3, p 232

outage notification improvement closer to one minute as opposed to RIE's estimated 22 minutes.

Q. DID YOU REVIEW THE COMPANY'S RESPONSES TO DIVISION DATA REQUESTS DIVISION 3-1 THROUGH 3-21 WHICH PROVIDED EXPLANATION OF THE MANNER PPL USED TO DETERMINE THE AVERAGE 22-MINUTES IN IMPROVEMENT IN OUTAGE NOTIFICATION USING AMF?

A. Yes.

Q. WHY DOES THAT NOT CONVINCE YOU THAT AMF WOULD RESULT IN THE 22-MINUTE IMPROVEMENT IN OUTAGE NOTIFICATION?

A. There are multiple reasons. First, PPL had AMF fully deployed by August 2019 and this is when it started their sampling. Thus, the majority of customers would have been aware the new meters automatically reported the outages; and therefore, the customers would be much less likely to call in an outage immediately. The customer would typically only call in an outage well after it had occurred, when they thought the response was not rapid enough, and would not call as they would have when they did not expect the meter to automatically notify the utility. Second, as PPL states, the outage duration was not affected. That would be because the crew notification and truck roll should be nearly the same since it occurs upon initial OMS notification, which would be close–if not identical to the notification timeline whether initiated by a customer's call or conversely, via an AMF automatic notification. The SAIDI and 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. Additionally, as the engineer responsible for three different utility systems, prior to AMF implementation we received multiple outage calls almost immediately upon the outage. Once AMF was implemented, for instances where a customer chose to call in an outage, the change in time of notice was seconds, not minutes. Third, it is illogical that in Pennsylvania or Rhode Island a customer on average would wait 22-minutes to call in an outage. The time difference analysis by PPL is after AMF is deployed, and one would not expect calls to arrive based on customer knowledge until the customer felt the response was too slow, and a customer would not likely ever wait an average of 22-minutes to call in an outage. Fourth, the PPL data shows IVR customer calls went from 45 percent in 2019 to 13 percent in 2021. This serves as further support that people recognized the meters were sending the automated notification. Additionally, in my experience, calls that were not immediately received were typically people inquiring when the power would be restored, not to notify the utility of the outage. The 22-minute differential in notification time should not be used.

Q. IF THE COMMISSION ACCEPTS THE BCA AND THE 22-MINUTE OUTAGE RESTORATION IMPROVEMENT IN BENEFITS, WHAT WOULD YOU RECOMMEND IN ORDER TO PROTECT THE CUSTOMER?

A. The customer should receive some form of protection from the claims being put forth by the Company associated with AMF economic benefits. The 22-minute outage improvement claim should be validated through Commission imposed reliability performance requirements with penalties for failure to achieve specific thresholds. The Company has claimed under the ISR Plan Vegetation Management approach the change of a 15 to 18 percent reduction in outage frequency. This should be combined with the 22-minute claim. The existing threshold is 1.05 for SAIFI and 71.9 for SAIDI. These thresholds should be reduced to 0.80 for SAIFI and 55.0 for SAIDI to validate the benefit claims made by the Company as a justification for AMF rapid advancement. The

Commission would require annual reporting on actual performance compared to thresholds, and apply penalties when applicable.

Q. THE COMPANY IS SUBSCRIBING SOME VVO/CVR BENEFITS TO THE AMF SYSTEM. DO YOU AGREE WITH THAT?

A. No. Over the course of numerous conferences and presentations by the Company, it has sent many mixed messages. The Commission needs to understand that the preponderance of VVO/CVR was demonstrated in the ISR Plan pilot program and could have continued with the then selected technology. The Company demonstrated demand and energy savings which were conservatively 3 percent and appeared could reach 5 percent. Later, when the Company was asked how much savings had been forever lost as a result of the suspension of the VVO/CVR expansion, it answered none since the DER penetration has essentially eliminated the VVO benefits. We believe there will be VVO/CVR benefits and the program should not be forever suspended. The BCA for the AMF, however, should not incorporate these VVO/CVR benefits since they were always part of the earlier ISR Plan program for VVO/CVR and AMF will produce little if any incremental benefit. Furthermore, if the Company's claim that DER has eliminated the VVO/CVR benefits then, again, this is an additional argument not to include VVO/CVR benefits in the BCA.

Q. THE COMPANY CHARACTERIZES AMF AND GRID MODERNIZATION AS MAJOR SOLUTIONS FOR RELIABILITY AND OUTAGE REDUCTION. COULD YOU PROVIDE SOME EXAMPLES OF WHY THAT IS AN EXAGGERATION?

A. A recent Duke Energy outage in December 2022 which resulted from a severe cold snap in North Carolina is one example. Significant portions of the system were down for multiple days and rolling blackouts were necessary, even though Duke Energy has had

AMF in place for years and has many grid modernization technologies installed, including self-healing circuits. None of this technology solved the major overload condition or mitigated the outage duration. The Duke Energy Moore County, North Carolina substation failure resulting in 45,000 customers being out for 8 days is another example of technology not being the solution. Both these examples demonstrate that a utility with AMF and a massive investment in grid modernization technology cannot overcome the basic need for capacity and infrastructure in order to provide for a safe and reliable system. The Company is overstating the value of the metering technology. That is not to say it should not be deployed. What the Division recommends is a more measured and structured approach to the deployment with a greater sense of mitigating the rate impact on the customer.

Q. DO YOU EXPECT COMMUNICATIONS AND TECHNOLOGY DEFICIENCIES WILL ADVERSELY IMPACT THE PERFORMANCE?

A. Yes. The deployment of any new technology will have growing pains and a series of deficiencies which will create operational difficulties and customer disruption in the first few years. There will be areas with communication problems and manual meter reading at times will be required. There are areas which will require a series of solutions to unsatisfactory communications coverage. These issues occur on every AMF system installation. There is customer dissatisfaction and extra company expense to resolve these issues. None of this has been outlined in the Company's Business Plan or BCA. The Company has failed to incorporate any costs in the BCA associated with these eventualities.

Q. ARE THERE OTHER COMMUNICATION SYSTEM ISSUES?

A. Yes. In the Company's ISR Plan FY2024 filing it removed the advancement of the fiber optic plant installation as a result of supply chain delays. The communication industry is rapidly expanding with fiber and new cellular technology. Additionally, electric utilities, particularly rural utilities, are rapidly expanding broadband on their electric poles to serve the very underserved rural communities. This is placing an unprecedented burden on the communication material manufacturers. Further delays in the supply chain can be expected, thus a complete roll out of all the AMF functionality in the 3.5 year estimated time frame is overly optimistic. Since the communication system full functionality is essential to gain all the benefits of AMF and to achieve full ADMS functionality, it is only prudent to estimate a longer timeline and mitigate rate impact. Also, the Company needs to develop and implement a plan for communication system coverage difficulties. There will be gaps in the coverage, interference from existing Wi-Fi devices, and structures will block the signal path. As such, additional communication equipment will be needed and will have to be installed in a timely manner so metering data will be available for billing. There will be a much larger number of estimated bills during the transition, and this will be disruptive and create customer dissatisfaction. Some utilities have taken years to overcome these issues. Without a seamless communications scheme, which is most certainly not going to be the case, the full benefits of the AMF deployment will not be available. There may, in fact, be a loss of confidence in the new system by some customers. These delays and costs should be incorporated into the plan and the BCA.

Q. THE COMPANY HAS INDICATED THAT TIME VARYING RATES CANNOT BE IMPLEMENTED WITHOUT AMF. DO YOU AGREE?

A. This is not accurate. Utilities have implemented time of use rates going back to the early 1980’s, long before advanced metering technology. The AMR metering system affords the ability to advance TVR. While AMF adds to the flexibility and variability of TVR, it is not essential in order to implement. RIE incorrectly attributes all the benefits of TVR to AMF meters. For that reason, the benefits of TVR should be removed from any BCA.

Q. CAN AMF IMPROVE THE PLANNING FUNCTIONS OF RIE?

A. With 15-minute data, RIE will have the exact load at every meter during the hour of the system peak and this information can be used to better plan where system improvements will be required to handle growth. This data could be compared to supervisory control and data acquisition ("SCADA") data to verify the accuracy of both sets of data. RIE will also know which DER systems are operational during the system peak and during off peak periods, which will then allow contingency cases to be explored if DER is not available. RIE will also know the minimum load on each section of line which can assist them to determine if additional DER can be supported and not create reverse power flow. The data will also aid in calculating system losses and developing action plans for improvements where needed. Overall, AMF data will dramatically improve the CYME engineering software model and, thus, the Long-Range Planning and ISR Plans.

Q. SHOULD THERE BE SOME FORM OF ASSURANCE THE COMPANY ADVANCES ALL THE ENGINEERING BENEFITS FROM THE AMF SYSTEM?

A. Yes. We have seen promises of AMF system benefits fail to be advanced. There needs to be some mechanism to assure that all the AMF proposed benefits are realized and actually advanced by the Company. We do not currently have a proposal for such a mechanism, since the AMF funding is being proposed to be outside the ISR Plan, while historically all metering capital costs were captured under the ISR Plan Non-Discretionary category.

Q: RIE HAS BOTH ELECTRIC AND GAS UTILITIES UNDER ITS CORPORATE UMBRELLA, AND HAS PLANS TO INSTALL AN AMF METERING SYSTEM

FOR BOTH. DOES THIS IMPACT THE DEPLOYMENT OF AMF METERING FOR THE ELECTRIC UTILITY?

A. Given that the Company plans to deploy an AMF metering system for the electric utility first, it will need to have all the infrastructure in place for this deployment. While the advanced meters for the electric utility are not compatible with gas utility meters, there are systems in common that can be used jointly. For example, the mesh network may be used for both electric and gas operations. It is also possible that some of the billing hardware and software can be shared. In that these systems can and should be used in common, costs should be allocated and shared appropriately according to cost-of-service principles and each utility's share in the benefits from any economies of scale arising from common use of systems.

V. BENEFIT-COST ANALYSIS

Q. TURNING TO YOUR ANALYSIS OF RIE'S BCA, HOW HAVE YOU APPROACHED THIS ISSUE?

A. First, we focused on the benefits side of the analysis. We took a broad overall look at the BCA to determine if there are general issues that impact the overall analysis of the estimated benefits and are not category-specific. Then we turned to the specific benefit line items contained in the BCA and looked at RIE's determination of benefits by category.

Q. WHAT HAVE YOU FOUND IN YOUR REVIEW OF THE OVERALL BCA?

A. There are four areas of interest arising from our overview of RIE's estimated benefits – a) the use of a discount rate specific to data taken from the AESC-2021 Report to determine present value, b) the use of estimates of the social cost of carbon taken from this same data source, c) the overall assessment of the benefits of time-dependent rates, and d) specific categories of benefits included and excluded in the Company's BCA.

Q: WHY IS THE DISCOUNT RATE IMPORTANT AND HOW DOES RIE APPLY IT?

A. RIE is requesting authority to make some large upfront investments to replace AMR meters and equipment with AMF meters and systems that are expected to provide benefits accruing a considerable time after these costs are incurred – over the next 20 years in the RIE analysis. To make decisions about whether to proceed, it is imperative to compare benefits and costs on an equivalent basis to get Net Present Value. The general purpose of the discount rate is to determine the equivalence between the value of all benefits and costs as if they were received and incurred today – present value – and the value of all benefits and costs received and incurred over the expected life – nominal or future value. To do this the Company will need to discount expected future benefit and costs over the projected time frame by a factor that will yield equivalence to present values of these expectations. This factor is the discount rate.

The discount rate that yields this equivalence is the opportunity cost – a measure of what must be given up to get something else. Stated in the language of finance, it is the foregone rate of return. The discount rate that approximates the opportunity cost has three components: 1) a true return component – the time value of money measured by the prevailing real interest rate in a risk-free investment, 2) an expectation of future inflation component as measured by a projection of future inflation, and 3) a premium component to compensate for the risk of not realizing expected benefits after the costs are incurred. In the field of public utilities, this is generally set at the regulated utility's allowed post-tax weighted average cost of capital ("WACC"), as this is what the regulating authority has decided is a fair rate of return of comparable risk for both the regulated utility and the consumer which incorporates all three of these components in a discount rate. RIE uses the WACC as a discount rate in the determination of the present value of many of its benefits and all its costs. However, it also uses a different discount rate in the determination of present value of benefits from categories using AESC-2021 Report derived data as well as for data estimating benefits to society for emissions reductions. In its BCA, the Company employs three different discount rates for benefits.

RIE uses a discount rate of 2.00% to determine the present value of expected future benefits for all of its estimates that are based on AESC-2021 Report data. On this RIE states[2]:

> "The AESC discount rate of 2.0 percent was derived as described in Section 11.2, p.136, of the AMF Business Case: 'The Company chose the 2% discount rate because the avoided cost values developed in the AESC 2021 report are shown in $2021 dollars ("real" dollars) regardless of which year was being forecast. Rhode Island Energy inflated these values by 2% to develop the nominal values and discounted them by 2% to get back to the initial "real" values, adjusted to be $2022.' The inflation rate was determined by looking at the inflation rate included in the AESC report (2.0% shown on page 361 of the 2021 AESC Report developed by Synapse Energy Economics) and the average U.S. inflation rate for the past 20 years. Because the AESC report values were in real values, the discount rate needed to match the inflation/escalation rate to match the real values."

This goes against the generally accepted economic definition of discount rate because it only accounts for an estimate of the expected future inflation and does not account for the other two components of a discount rate – the time value of money and any risk of not achieving the expected benefits. Therefore, the 2.00% rate used by RIE is unrealistically low and drives the BCA ratio much higher[3]. Using the WACC (adjusted to reflect that 2.00% inflation has been included in the RIE discount rate) to determine the present value

[2] RIE response to Division data request Division 1-22.
[3] It should be noted that in its initial application to implement an AMF metering system, National Grid used its most recently approved WACC to determine the present value of many of the benefits that Rhode Island Energy has used the lower 2.0% discount rate.

of expected future benefits as estimated using the AESC provided data on cost estimates, the Present Value ("PV") of benefits is reduced significantly. Using the adjusted WACC for a discount rate, instead of a 2.00% discount rate for all the benefit categories that are derived from AESC-2021 data, reduces the RIE estimate of PV of benefits from $729.2 million to $600.0 million and the benefit-cost ratio from 3.9 to 3.2. I recommend using the WACC discount rate as this more realistically represents the opportunity cost.

As for the 3.00% discount rate that RIE used to determine the present value of emissions reducing benefits, there has been and continues to be debate within the environmental and economics communities about the appropriate discount rate. The debate centers around how much weight to give to future generations in determining the appropriate discount rate, since the traditional use of a discount rate may not provide enough weight to the long-term future. While there still exists some disagreement, the present state of the argument tends toward the lower 3.00% rate as this is the rate that is often seen used in governmental analysis of emissions-reducing projects. While I do not propose that the RIE analysis of the emissions reduction benefits be reassessed using the more traditional WACC discount rate, I note that if this were to be done, present value of benefits would be further reduced to $513.1 million and the benefit-cost ratio to 2.7.

Q. WHY IS THE ESTIMATE OF THE SOCIAL COST OF CARBON IMPORTANT AND HOW DOES RIE USE IT IN THE BCA?

A. 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. Both of these are expected to have important impacts on electricity usage – particularly at times of system peak – and therefore provide a very sizable incremental boost in achieving the climate mandates that the Rhode Island legislature has enacted.

The estimate of the social cost of carbon dioxide and greenhouse gas ("GHG") emissions in general forms the basis for the determination of benefit estimation for any of the characteristics of the AMF system that allow for additional reduction in these emissions. Any reduction of energy has the potential to reduce GHG emissions and other emissions because of the reduced demand to generate electric energy using carbon-based fuels. This is particularly true for energy usage reduced during on-peak times, as these times are more prone to employ generators that are GHG emitters.

RIE uses estimates of the social cost of carbon (as well as NOx and public health benefits) to estimate the benefits of the incremental reductions in energy usage and demand due to the enhanced transparency enabled by the AMF metering system. These estimated benefits arch over several of the program categories included in RIE's BCA and are derived by determining results that are enabled by the enhanced capabilities of an AMF metering system from all the appropriate program categories of benefits, estimating the impact of each of these program categories, and applying an estimate of the avoided cost per unit of each of these expected emissions reductions in each program category. These overarching program categories are: Energy Insights Savings, VVO/CVR, Whole House TOU/CPP – Opt-In, EV/TVR – Opt-In[4].

The predominant driver of benefits from emissions reduction is from the reduction in carbon emissions, so our general critique of the RIE BCA expected benefit estimates is focused on this source, although the same concerns are attributable to the estimates of

[4]Remote Metering, Reduced Field Investigations and AMF Meter Reading are also included, but these expected benefits are derived from reduced vehicle usage and are not directly associated with the reduction in electric usage.

expected benefits from NOx reductions and those attributable to public health benefits. If the initial estimates of the avoided costs from reduced electric usage are wrong, then the estimates of the expected benefits will be wrong.

RIE bifurcates the estimates of expected benefits from carbon reduction into two separate benefit categories – monetized and non-embedded. The estimates of expected monetized benefits arise from the avoided cost of not having to pay the Renewable Portfolio Standard ("RPS") compliance charge on the energy avoided from each program category. The estimates of expected non-embedded benefits arise from the avoided social cost from less carbon emissions from less generation of electricity from carbon-based fuels needed to serve load.

Q. HOW DOES RIE ESTIMATE THE EXPECTED BENEFITS FOR THE MONETIZED PORTION OF CARBON REDUCTION?

A. The estimated expected benefits for the monetized portion of carbon reduction are straightforward. The estimated amount per MWh that represents direct payments for Renewable Portfolio Standards ("RPS") compliance is multiplied by the amount of energy expected to be reduced by the respective program categories. It is reasonable to expect that as Rhode Island experiences more renewable distributed energy resources on its system, and more renewable generation is added to the overall supply, the RPS Compliance Charge should be reduced; up to and including to zero as Rhode Island approaches achieving a zero-carbon economy. It appears that RIE has not addressed this in its estimates of monetized benefits from AMR.

Q. HOW DOES RIE ESTIMATE THE EXPECTED BENEFITS FROM THE NON-EMBEDDED PORTION OF CARBON REDUCTION?

A. The estimate of the expected benefits from the non-embedded portion of carbon reduction is based on an estimate of the societal cost of carbon ("SCC") multiplied by the anticipated reduction in energy usage from the respective program categories. There are two issues with the way that RIE estimated the expected benefits from non-embedded carbon reduction. First, there is debate as to the appropriate estimate for avoided cost of carbon to society. I will refer to this as the marginal impact. Second, it is reasonable to assume some recognition of the value of RIE's efforts regarding meeting the climate mandate goals in Rhode Island which require increasing amounts of renewables in the generation of electricity and ultimately a zero-carbon economy. I will refer to this as the inframarginal impact.

As to the marginal impact, there is considerable debate as to what the SCC is. The AESC-2021 Report, from which RIE adopts data, reports a range of SCC estimates taken from a meta-analysis of between $53 and $870 per short ton of carbon in 2021 dollars (p. 176). The SCC that RIE uses from the AESC-2021 Report assumes a relatively high value of SCC and with it an estimate of the expected benefits from the marginal impact. Using a lower estimate of the SCC will lower the nominal and the present value estimates of these program category benefits from the marginal impact.

As for the inframarginal impact, if RIE is successful in meeting the requirements for renewables as set forth in the state's recently adopted goals for renewable content of the electricity supply, the result will be less carbon reduced per MWh of energy avoided by the affected program categories due to diminishing returns to scale. This diminishing return occurs because meeting the renewables mandate will 1) make the entire system less carbon intensive in the future, and 2) diminish the incremental carbon reduction benefit from each

MWh of avoided energy usage. Both the marginal and the inframarginal impact suggest that the RIE estimates of these non-embedded benefits are overstated.

Q. HOW DOES RIE ASSESS THE BENEFITS OF ITS TIME-DEPENDENT RATES?

A. The menu of the Company's time-dependent rates includes its offerings of whole-house time-of-use ("TOU"), whole-house Critical Peak Pricing ("CPP") and an Electric Vehicle time-varying rates charging rate ("EV/TVR"). Utilities have been successfully offering time-dependent rates such as these to their consumers for many years prior to the advent of smart meters. RIE could have time-varying rates with existing metering technology. Attributing all the benefits of time-dependent rates to AMF meters is an overstatement.

Q. DO YOU HAVE OBSERVATIONS REGARDING EV/TVR BENEFITS?

A. Yes. The Company estimates benefits of $112.4 million on a nominal basis and $79.5 million on a PV basis due to consumers opting in to EV time varying rates. However, the Company has not considered how EV/TVR will be implemented or administered. During the PUC technical session held February 22, 2023, the Company indicated that the business case did not assume that consumers with EV chargers connected "behind the meter" would require a second AMF meter to specifically measure and bill EV charging consumption. If the primary AMF meter at a consumer site is utilized, then that consumer could participate in a whole house TVR. However, the AMF data would not distinguish EV charger usage from any other home appliance with the accuracy required for utility billing. Alternatively, the Company could offer EV managed charging options that provide consumer incentives to adjust charging times by relying on smart charger data, vehicle telematics or other devices. This would not require an AMF meter, and in fact, can be accomplished without utility meters. The point is that if an AMF meter is not used to apply and administer EV time varying rates or manage charging, there is not an associated AMF benefit. This is an area that requires more detailed evaluation and potential adjustments, taking into consideration that EV charging programs are not dependent on AMF and that the benefits are overstated. To be clear, we are not recommending that all EV chargers be separately metered which would require unnecessary infrastructure. The Company is treating EV load separately from any other customer loads that would be targeted in a demand reduction program. It is not clear why that separation is required when the Company must manage system capacity requirements considering aggregate loads. If the Company desires to pursue a separate EV load management program, however, we are advocating for a cost-effective approach to manage EV charging which may be a separate solution with its own set of costs and benefits. The EV benefits captured in the Company's BCA should be removed since they are not directly attributable to the AMF system. This is an overreach by the Company.

Q. AS FOR THE SPECIFIC CATEGORIES OF BENEFITS CONTAINED IN THE RIE BCA, PLEASE DISCUSS WHAT YOUR ANALYSIS DETERMINED.

A. This testimony will address the concerns about the specific estimates of expected benefits that were raised during our analysis of the BCA, beginning with the biggest estimate of present value ("PV") expected benefit and proceeding down through smaller estimated expected benefits.

Q. WHAT WAS THE BIGGEST CONTRIBUTOR TO THE OVERALL ESTIMATE OF EXPECTED BENEFITS IN THE RIE BCA?

A. The biggest estimate of expected benefit arises from Faster Outage Notification. The estimate of expected PV benefits is $169.2 million or 23.2% of the total RIE estimated expected benefits. First, as discussed above, the estimated benefit of 22 minutes faster notification due to the difference between the notification from Last Gasp by the AMF meters and the consumer call in protocol by the AMR meters is an overreach. Based on this analysis, the benefit should be no more than one minute of improved notification time. Another issue of concern is the use of the Interruption Cost Estimate ("ICE") Calculator to derive the implied value to the consumer of reduced time based on the inner workings of the calculation. The immediate question is whether the ICE Calculator is the appropriate tool for this evaluation. While the ICE Calculator is a robust tool developed from a mega-analysis of many different estimates of outage costs that attempts to adjust the findings to tailor results on a state-by-state basis, there are several questions that come into play. First, the ICE Calculator appears to use the Rhode Island mix of commercial and industrial consumers and their associated valuations of lost load to determine the non-residential consumer component of an avoided cost estimate of an outage to impute a benefit from system improvement. RIE has indicated that its largest industrial consumers already have MV-90 meters which are not being replaced as a part of the AMF metering replacement program. The use of the ICE Calculator that incorporates industrial estimates of benefits would therefore overstate the expected benefits, since these meters are not being replaced with AMF meters.

Finally, the estimate of the expected benefit from faster outage notification uses a discount rate of 3.00% to derive its present value for the BCA, which the Company states is the Societal Discount rate. For the reasons amplified above, this seems to be out of touch with the concept of opportunity cost which would be better approximated by the discount rate – also used in RIE's BCA – of its most recently authorized rate of return- at 6.97%.

Q. ARE THERE OTHER ESTIMATES OF EXPECTED BENEFITS THAT CONTRIBUTE HEAVILY TO THE RIE BCA BENEFITS ANALYSIS?

A. Yes. The next two biggest estimated expected benefits categories are non-embedded CO2 benefits: VVO/CVR and non-embedded CO2 benefits: Energy Insights, both of which are addressed in our general BCA comments on non-embedded benefits above. Moving down the list, the next biggest contributor is Electric Bill Reduction. The estimate of expected benefits from this category is derived by multiplying the expected annual savings from some consumers reducing their energy usage through access to more granular and much more timely data. This estimated energy usage reduction is then multiplied by the expected residential and commercial rates over the 20-year BCA period. The amount of energy savings from the reduction in the commodity component of the all-in power rate is then backed out for an estimate reduction in billing units applied to the non-commodity components of the consumer's rate schedule. Care should be taken here not to exclude charges that are deemed to be non-bypassable in the billing tariffs.

Q. ARE THERE ANY OMISSIONS IN THE RIE BCA THAT YOU HAVE FOUND THAT YOU RECOMMEND TO BE INCLUDED?

A. RIE estimates the AMF benefit from reduction in theft at $60.61 million (nominal) and $24.46 million (present value). The Company treats this as a transfer – not to be included in net benefits – because it states: "…reducing the theft increases the amount those stealing electricity pay and reduces the amount the rest of the consumers pay." We would argue from a rate-making standpoint that this should be included in benefits as it flows to the bottom line for rate-setting purposes. This would improve the overall benefit-cost ratio by 0.1 point.

RIE also estimates the benefit of electromechanical meter accuracy given that older EM meters tend to slow down as they age while digital meters do not. The estimates of this benefit are $31.47 million (nominal) and $17.89 million (present value). Considering the

Company's meter testing and accuracy requirements, this benefit is significantly overstated. Even so, the Company treats these as a transfer and not as a benefit. We would suggest at a minimum, considering this, at least partially as a qualitative benefit as it accrues to the bottom line for rate-setting.

Q. ARE THERE OTHER CONCERNS ABOUT THE RIE BCA?

A. The BCA as presented by RIE is a complex model of many moving parts. There are 37 benefit categories for which RIE has provided detailed estimates totaling approximately $706.1 million PV. In addition, there are 41 benefit categories for which RIE adopted the previous estimates provided by National Grid totaling approximately $23.1 million PV, bringing the total Company estimate of expected benefits to $729.2 million PV. Many of these estimated expected benefits are intertwined with other benefits that, if assumptions are misstated or if there are mathematical errors, will impact more than just the benefit being estimated.

Q. HAVE YOU PREPARED A SUMMARY OF THE CHANGES THAT YOU SUGGEST IN THE BENEFIT-COST ANALYSIS?

A. Table 1 shows the incremental changes to the expected benefits relative to the RIE BCA that I have discussed above, along with the incremental changes in the B-C ratio.

TABLE 1: CHANGES TO EXPECTED BENEFITS ANALYSIS

Adjustment	Nominal	Present Value	Diff in PV	B-C Ratio
RIE BCA (AS FILED)	1059.3	729.2		3.9
Use WACC Discount rate for AESC-2021 numbers	1059.3	600.0	(129.2)	3.2
Remove 22-minute faster restoration benefit	815.5	430.8	(169.2)	2.3
Remove VVO/CVR benefit	646.6	346.4	(84.4)	1.8
Remove whole house TOU/CPP benefit	531.5	291.5	(54.9)	1.6
Remove EV/TVR benefit	419.1	241.7	(49.8)	1.3
Lower societal cost of carbon				

Lower RPS	These would lower the overall present value of benefits but are qualitative and not calculated			
Add theft benefit	479.7	266.2	24.5	1.4

VI. REVENUE RECOVERY

Q. HAVE YOU ANALYZED RIE'S PROPOSED PLAN FOR COST RECOVERY?

A. Yes, I have. RIE proposes to institute an AMF Factor designed to recover actual costs incurred during a prior six-month period through a non-bypassable volumetric ($/kWh) charge assessed to each rate schedule using allocation factors that were developed for RIE's latest distribution rate filing and agreed to in a settlement agreement. The AMF Factor is proposed to be adjusted every six months for known actual incremental increases in costs at least until the next Company filing for an increase in base distribution rates. Such filing is barred for at least 3 years from May 25, 2022 in accordance with the terms of the Division's Order in Docket No. D-21-09.

Q. WHAT ARE YOUR CONCERNS ABOUT THE PROPOSED PLAN?

A. First, the Commission rules and regulations have procedures in place for cost recovery. These are: 1) annual Infrastructure, Safety and Reliability ("ISR") Plan filings in which capital expenditures are proposed, analyzed for reasonableness and approved for recovery in rates as appropriate, and 2) periodic base distribution rate filings for operation and maintenance expenditures are proposed, analyzed for reasonableness and approved for recovery in rates as appropriate. Given these existing procedures, the Company proposal for cost recovery through an AMF Factor is not necessary. Second, cost recovery by a volumetric ($/kWh) charge to recover costs that are mostly fixed in nature runs against general principles of electric rate-setting. Third, the allocation to each of RIE's rate classes is based on revenue allocation analysis which draws on data from an allocated cost of service study ("ACOSS") that is at least six years old and further, the allocation factors were developed with an overarching goal to make significant progress toward a more unified rate class contribution to RIE's allowed overall rate of return on capital.

Q: YOUR CONCERNS REFER TO COMMISSION PROCEDURES FOR COST RECOVERY. DO YOU HAVE A RECOMMENDATION?

A: Yes. I would recommend that the Commission require the Company to use the ISR Plan filing for AMF capital cost recovery; and base rate proceedings for AMF O&M, IT costs, and for assessments and tracking of how well the Company has met its promises of the benefits of AMF metering. These procedures have long statutory standing and allow for complete review of costs for reasonableness, and have the benefit of being all inclusive and transparent. Furthermore, the issues of rate-setting principles and cost-of-service principles can be addressed during base distribution rate filings at the same time as costs are reviewed for reasonableness.

Q: YOU REFER TO USING A VOLUMETRIC CHARGE ($/KWH) TO RECOVER THE COSTS OF AMF DEPLOYMENT. WHAT SPECIFICALLY IS YOUR CONCERN?

A. General rate-setting principles posit that expenses that vary by the number of consumers be recovered through a customer charge ($/Customer-month), that expenses that vary by capacity requirements be recovered through a demand charge ($/kW-month), and that expenses that vary by energy usage be recovered through an energy or volumetric charge ($/kWh). In its presentation on benefits and costs, RIE separates out costs by capital and operating expenses. Of the total estimated nominal costs of AMF deployment of $289 million, nominal capital expenses account for $169 million, or 59%, with nominal operating expenses accounting for the remainder of $120 million or 41%. Capital expenses are generally fixed in nature and therefore represent customer-related or demand-related expenses. Most of the estimated operating expenses arise from annual software licensing and, while these annual expenses relate to operations, in projects like this one it is customary to capitalize some of the operating expenses related to the initial installation of equipment and systems. The bulk of the project expenses are capital-related and do not vary by energy usage.

Nearly all these expenses are created by the number of consumers whose meters will be replaced by AMF meters and are, therefore, customer-related expenses. If there are expenses that vary by either capacity requirements or by energy usage, we are not aware of them. Capital expenses are fixed in nature and are generally added to the rate base so that the costs for recovery through rates are determined by depreciation, tax expense and a return on investment over an extended period.

Therefore, if general rate-setting principles are a guiding principle, consideration should be given to cost recovery through at least a partial assessment from an increase in the customer charge in each rate class and not rely exclusively on a volumetric charge that carries with it an assumption that the cost varies with energy usage. These concerns can be assessed in the Company's next base distribution rate case.

Q. WOULD YOU PLEASE ELABORATE ON YOUR CONCERN THAT THE COMPANY'S PROPOSED PLAN FOR COST RECOVERY SHOULD ACCOUNT FOR THE RISK OF FAILURE TO DELIVER EXPECTED BENEFITS TO THE CONSUMER?

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

Finally, in its proposed plan the Company proposes that they retain 20% of non-outage O&M benefits as an incentive for the Company to maximize benefit realization until the next base distribution rate filing, meaning that 80% of the non-outage O&M benefits would be used to offset incurred costs in the six-month AMF Factor. We propose that 100% of the benefits be offset against costs, as opposed to just 80%.

VII. DATA GOVERNANCE

Q. HAVE YOU REVIEWED THE COMPANY'S DATA GOVERNANCE AND PRIVACY STATEMENTS AS A PART OF ITS APPLICATION?

A. Yes. We have reviewed both of RIE's statements contained in its Application in Book 2, Section 10.2 -- Cyber and Privacy Protections Using Data Governance. We have also reviewed

RIE's policies as set forth in its Application in Book 2 – Attachment G: Cybersecurity, Data Privacy and Data Governance Plan, along with the plan as set forth by the Company's predecessor, National Grid.

Q. DO YOU HAVE ANY CONCERNS ABOUT RIE'S DATA GOVERNANCE AND PRIVACY STATEMENTS AND POLICIES?

A. In the documents included in its Application, RIE provides an overview of its approach to customer data privacy in Section L of Attachment G, which consists of a brief statement as to which guidelines it will follow in conducting "…a privacy impact assessment (PIA) before any deployment". Further, it states that the PIA will help in identifying and managing any privacy risks and meeting legal requirements. In contrast, Section 5 of the data governance statements submitted by National Grid is 13 pages long and contains detailed information regarding how National Grid's AMF deployment intended to meet its obligations to preserve customer privacy that is consistent with cybersecurity requirements and that facilitates data access in furtherance with grid modernization and clean energy objectives. The National Grid policy is very detailed in its overarching concern that the customer has the right to access their data, to share the data with third parties, and to integrate this data with home-enabled devices. The Company should be required to present a detailed Data Governance plan for assessment by the stakeholders and Commission.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE ISSUE OF DATA GOVERNANCE?

A. We recommend that RIE be required to adopt policies proposed by National Grid in Docket 5113 and, further, that any monetary benefits that the Company receives from the customer-approved sale of data be fully accounted for as an offset to revenue requirements for rate-setting purposes.

VIII. IMPACT OF INCREASING ELECTRIC LOADS

Q. WHAT HAVE YOU FOUND REGARDING EXPECTATIONS OF ADOPTION OF ELECTRIC VEHICLES IN THE U.S. FUTURE?

A. The current projections for the expansion of electric vehicles ("EV") in the United States exhibit a range depending on the source. A sampling of this range for EV growth over the next five years is in the range of 23 to 30% percent compounded per year with the increasingly upward trend showing no sign of abatement in the near term. The passage of the Infrastructure and Investment Jobs Act which became law on November 15, 2021, provided, among other things, $7.5 billion in new spending to expand the nationwide network of EV charging stations. This breakdown of a major barrier to EV adoption, coupled with an increase in attention to National energy security through energy independence and aggressive national goals to achieve zero carbon emissions should only enhance this trend of increasing penetration of EVs in the United States.

Q. WHAT HAS RIE PROJECTED FOR GROWTH IN EVS IN THE STATE?

A. RIE has included inputs into its BCA of benefits from EVs through various programs. This requires an estimate of expected numbers of EVs in the state along with an estimate of the expected energy usage of these vehicles. RIE has included projections of EV penetration in the state that exhibit a 35% annual compound growth rate from 2022 to 2027 and a 24% annual compound growth rate for 2022 to 2041. The Company is relying on the GMP load forecast which does not appear achievable, particularly when the Department of Energy[5] indicates that there were 2,500 light duty EVs registered in Rhode Island in 2021 while

[5] https://afdc.energy.gov/vehicle-registration

RIE expects that number to grow to 10,605 in 2023. These projections show an expected increase faster than the national statistics cited above, with a slowing as saturation levels increase over time as one would expect. The expected annual compound growth estimates of the electric usage to charge these additional EVs is 38% from 2022 to 2027 and 25% from 2022 to 2041.

Q. WHAT HAVE YOU FOUND REGARDING EXPECTATIONS OF CONVERSIONS TO ELECTRIC HEAT PUMPS AS A HEATING SOURCE IN THE U.S.?

A. The latest data available from US Department of Energy – Energy Information Administration compiled from 2020 surveys shows the Northeast continuing to be the least reliant region in the continental United States on electricity as a primary heating source. The Northeast as a region continues to lag the national average with a little over one-half the national average of electric heat usage. As a state, Rhode Island ranks 45 out of the lower 48 states and the District of Columbia in electric heat adoption at 13% of total heat source being electric with carbon-based fuels accounting for 84% of the total heat source. Further, the International Energy Agency projects that the heat pump stock will jump from the current level of 180 million to 600 million by 2030 for a 16% per year increase. Recent improvements in the technological efficiency of heat pumps have continued to make the heat pump an increasingly viable alternative to carbon-based heating and less efficient cooling methods. All of this would indicate that the heat pump may continue to make inroads into the United States energy picture going forward.

Q. WHAT HAS RIE PROJECTED FOR HEAT PUMP ENERGY USAGE GROWTH IN THE STATE?

A. RIE, in the development of its estimate of expected benefits in its BCA, shows an increase in electricity usage from heat pumps increasing at an annual compounded growth rate of 34% from 2022 to 2027 and 21% from 2022 to 2041.

Q. HOW DO THESE ESTIMATES OF EXPECTED GROWTH IN ELECTRIC USE FROM EVS AND HEAT PUMPS AFFECT RIE?

A. RIE can expect the demands on its electric distribution system to increase as a result of the incremental loads from EVs and heat pumps. The Company has not demonstrated that operational issues exist or will arise from these increasing loads in the near term, and the probability of achieving the Company's forecasted pace and level of EV and heat pump adoption is low. RIE should be able to sufficiently manage increasing loads with current infrastructure and technology, including the Company's demand response program and possibly implementing an EV managed charging program that does not rely on advanced metering as previously discussed. Advanced metering will certainly help in system planning to project and evaluate longer term needs. In the future state where RIE must manage system peaks and also balance load and distributed generation on a more granular level, the Company will rely on AMF metering functionality for more complex rate structures and, ultimately, invest in technologies such as those presented in Grid Modernization Docket 22-56-EL. That future state, however, is not as imminent as RIE suggests. Furthermore, if EV and heat pump loads outstrip any actualization of the potential of end use rates or future load management programs, or if usage patterns do not shift the periods of maximum demand to non-traditional times of the day, RIE may need to expand the capacity of the electric distribution system to accommodate these incremental demands.

IX. SUMMARY, CONCLUSION AND RECOMMENDATIONS

Q. PLEASE BRIEFLY SUMMARIZE YOUR FINDINGS.

A. The findings that we have made are as follows.

1. Engineering, Operations and Deployment Analysis
    - Replacing AMR meters with AMF metering technology is necessary as AMR meters age, degrade and increasingly become less mainstream for maintenance and replacement, but is not as urgently necessary as the RIE timeline suggests.
    - RIE should have a separate Benefit-Cost Analysis for meter disconnect technology.
    - Benefits associated with faster outage notifications should be reduced to 1-minute.
    - Benefits associated with VVO/CVR enhancement should not be included in AMF benefits since these were part of an earlier ISR plan.
    - Communications issues have not been adequately addressed.
    - AMF metering technology is not necessary for the implementation of time-varying rates, and Company estimates of expected benefits should reflect this.
    - The costs of any facilities used in common with RIE's gas utility be appropriately assigned using cost-of-service principles to recognize these economies of scale.
2. Benefit-Cost Analysis
    - The discount rate that represents opportunity costs should be applied to get the present value of the estimate of expected benefit for benefit categories that use data taken from the AESC-2021 Report.
    - When estimating any expected benefits from the reduction of energy usage attributable to AMF metering technology, the impact of: a) alternative, lower estimates of future Renewable Portfolio Standard compliance fees due to less GHG emissions per MWh, b) diminishing returns to scale of carbon reduction per MWh as generation sources

become more carbon-free as a result of Climate Mandate goals, and c) the appropriate Societal Cost of Carbon, should be recognized.

- The benefits from time-varying rates should not be considered in the benefits of AMF deployment since these rates are not dependent on having AMF meters.
- Electric Vehicle time-varying rates can be implemented without the use of AMF metering technology, and the estimates of expected benefits should not be assigned to AMF.
- The benefits of reduced meter theft for AMF metering technology should be included, and the qualitative benefits of meter efficiency for AMF metering technology should be recognized.

3. Revenue Recovery

- Revenue recovery for capital costs should be through the ISR mechanism and non-capital costs should be deferred for consideration in the Company's next distribution base rate case. This will have the benefit of full and transparent review, including an updated cost-of-service study, a full review of rate-setting principles on rate design, and a forum for the assessment of achievement of the Company's obligation to provide certain levels of benefits.

4. Data Governance

- Provide for full privacy of ratepayer data and ratepayer consent for distribution of the data. Adopt a code of conduct to guide the Company in providing consumer protections equal to the provisions proposed by the National Grid AMF filing in Docket 5113.

5. Impact of Increasing Loads

- The Company projections of electric load expansion from expected future adoption of electric vehicles and heat pumps are optimistic when compared to national trends.

- Even with lowered expected future growth rates in these two technologies. RIE will need to assess system distribution and transmission capacity expansion and accommodate these incremental demands through system expansion as needed.

Q. WOULD YOU SUMMARIZE YOUR RECOMMENDATIONS?

A. Yes, we have 5 recommendations. These recommendations as discussed throughout our testimony are summarized in the following list.

The Company should obtain bid prices for the meters with and without the remote disconnect/reconnect feature.

1. The Company should be required to perform a separate BCA associated with the remote disconnect/reconnect feature. It should not incorporate the remote disconnect/reconnect feature in all the meters if the BCA does not demonstrate a clear benefit to the customer.
2. The AMF system Business Case BCA should be adjusted in the following manner:
    a. The Present Value of all data derived from AESC-2021 Report should be calculated using adjusted WACC as the discount rate;
    b. The benefits of time dependent and EV/TVR should be excluded from the analysis;
    c. The benefits of VVO/CVR should be excluded from the analysis;
    d. The benefits of improved outage restoration notification using the ICE Calculator should be adjusted down from 22-minutes to 1-minute[6];
    e. The ICE Calculator analysis should be adjusted to remove any benefits associated with large C&I customers; and

[6] If this recommendation is not adopted, RIE's actual reliability performance should be measured against thresholds of 0.80 for SAIFI and 55.0 for SAIDI with penalties for failure to meet requisite targets.

   f. The benefit from theft reduction should be included in AMF metering benefits.

3. Each system component and software integration not directly related to reading the meters and sending retail bills should be deferred to by 2 years in order to allow the meter reading and billing bugs to be reconciled first, and to mitigate the rate impact of the system capital and O&M costs.
4. The Company should incorporate the AMF metering data into its CYME engineering software modeling and the ISR Plan process within five years.
5. The Company should develop, for PUC approval, mechanisms that will be used to record and track costs and benefits in a manner that allows the PUC and stakeholders to compare the plan to actual results on an annual basis.

Q. DO YOU AND THE DIVISION SUPPORT THE PROPOSED RIE ADVANCED METERING FUNCTIONALITY DEPLOYMENT?

A. Yes. As has been stated several times throughout this testimony, the Division finds that, with the noted exceptions and recommendations for changes, the Company should proceed with the deployment of replacing its metering system with the AMF metering technology.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

RESUME OF:
WILLIAM FRANKLIN WATSON, PH.D.

Education

B.A., Economics, North Carolina State University
Master of Economics, North Carolina State University
Doctor of Philosophy with major in Economics and minor in Statistics,
North Carolina State University

Experience

January 2018 to Present
Principal, Econalytics, LLC

Econalytics is a consulting firm specializing in working with utilities in the application of the principles of economic analysis to meet existing operational challenges and to develop and implement strategic plans to operate successfully in the future environment.

August 2013 to May 2021
Adjunct Faculty member, Virginia Commonwealth University, School of Business

Taught undergraduate and graduate classes in economics and statistics.

January 2009 to January 2018
Regulatory Compliance Specialist
Old Dominion Electric Cooperative (ODEC)
www.odec.com

ODEC is a generation and transmission cooperative based in Richmond, VA that provides wholesale power to 11 full requirements electric distribution cooperatives in the states of Virginia, Delaware and Maryland.

Experience includes ensuring that ODEC and its 11electric distribution cooperatives met all federally mandated requirements to provide reliable electric service to their customers and as an integrated part of the national electric grid with entities such as the PJM Interconnection. This includes assisting in the development of regulatory standards to meet the energy policy requirements adopted by the United States Congress

February 2006 to December 2008
Financial Analyst
PowerServices, Inc.
www.powerservices.com

PowerServices, Inc. was a management consulting firm based in Raleigh, NC specializing in small to medium sized electric utilities.

Experience included analysis of cost-benefits of various projects, cost-of-service studies with rate design and recommendations, long-range planning for small to medium sized utilities, analysis of trends in the electric utility industry, review of regulatory filings and analysis of loss and assessment of system valuation for acquisitions.

January 2004 to January 2006
Senior Resource Analyst
Power Supply Division
North Carolina Electric Membership Corporation (NCEMC)
www.ncemc.com

NCEMC is a generation and transmission cooperative that provides wholesale power to 22 full requirements and 4 partial requirements electric distribution cooperatives in the state of North Carolina.

Experience included statistical analysis and hourly load forecasting for power supply budgets, developing strategies to optimize financial transmission right revenue for NCEMC's participation in the PJM Interconnection, working with renewable energy suppliers and individual electric distribution cooperatives to develop mutually beneficial power purchase agreements, liaison with North Carolina Utilities Commission which included overall responsibility for the preparation of the NCEMC Annual Integrated Resource Plan.

October 1999 to January 2004
Director, Strategic Analysis
Strategic Services Division
North Carolina Electric Membership Corporation
www.ncemc.com

Experience included statistical analysis for wholesale rates, strategic plan development, scenario planning, acquisition analysis and pricing, long-term rate projections and working with the NC Legislative Study Commission on the deregulation of the electric industry in North Carolina.

June 1981 to October 1999
Various positions with ElectriCities of North Carolina, including senior management
www.electricities.com

ElectriCities of North Carolina is an umbrella organization for North Carolina Municipal Power Agency Number 1 and North Carolina Eastern Municipal Power Agency (Power Agencies). These two Power Agencies are the wholesale suppliers of 19 and 32 municipally owned electric utilities in North Carolina, respectively.

Experience included development of wholesale rates for the Power Agencies, load forecasting and budgeting including long-term strategic planning, power purchase agreement negotiations with power suppliers, overall oversight of approximately 1400 megawatts of nuclear and coal-fired generation of which Power Agencies had joint ownership, development of plans for combustion turbine generation. I also developed a retail rate assistance program for Power Agency municipal utilities. As Director of Power Supply, I managed a staff of 6-8 people with engineering and accounting backgrounds and served as the Chief Budget Officer and Planner for the organization.

February 1978 to June 1981
Director of Economic Research Division
North Carolina Utilities Commission (NCUC)
www.pubstaff.commerce.state.nc.us

Experience included preparing expert rate and rate of return testimony in electric, natural gas telephone and water utilities petitions before the NCUC for increase in rates. Testified in numerous NCUC cases and one Federal Energy Regulatory Commission case subject to cross-examination by utilities' counsel. Also responsible for load forecasting and overall economic and statistical analysis of the utility industry. Managed a staff of 5 economists. Also worked on various antitrust cases providing expert economic analysis with the North Carolina Department of Justice.

Academic Experience

Adjunct Faculty member of the School of Business, Virginia Commonwealth University
Taught the following courses

- Foundations of Economics
- Business Statistics II

Adjunct Assistant Professor, Department of Economics, North Carolina State University.
Taught the following courses

- Introduction to Macroeconomics
- Economics of the Firm
- Statistics for Business Majors (first semester course)
- Statistics for Economists (second semester course)

Military
Commissioned Second Lieutenant, US Army Reserves, Armor Branch
Honorable Discharge from US Army Reserves, First Lieutenant

Other Accomplishments and Achievements

- Member and former chairman of the Graduate School Board of Advisors, North Carolina State University

- Former member of the College of Management Board of Advisors and former chairman of the Faculty Advisory Committee, North Carolina State University

- Former chair of the American Public Power Association's Pricing and Market Analysis Committee

- Member of the Southern Economic Association

Recent Publications

“NERC mandatory reliability standards: a 10-year assessment”, The Electricity Journal, March 2017.

“Reforming reliability standards: A perspective from economics”, The Electricity Journal, April 2018.

RESUME OF:
ROBIN W. BLANTON, PE

<u>EDUCATION</u>: CLEMSON UNIVERSITY, Clemson, SC
BS – Electrical Engineering

NRECA Management Internship Program - 2008

<u>REGISTRATIONS</u> Registered as Professional Engineer in North Carolina, South Carolina, Georgia, Tennessee, Florida, Mississippi, Kentucky, New Jersey, Maryland, Alabama, and Virginia

Member of the NRECA System Planning Subcommittee – The Subcommittee assist RUS in updating existing Standards and Bulletins and creating new ones such as the new Distributed Generation (DG) Interconnection Standard, System Planning Guide, Voltage Conversion Guide, Long-Range Planning Guide.

Participate with SERC as part of the audit staff of other utilities to ensure compliance with NERC and SERC Reliability Standards

IEEE Member assisting in writing the IEEE 1547-DG Interconnection Standards

Durham County Public Health Board 2000 – 2008

<u>EXPERIENCE</u>:
I am a registered Professional Engineer with a BS in Electrical Engineering and over 35 years of experience in engineering, operations, and maintenance of electric utility systems. I have worked for two electric cooperatives and a municipal electric system. I have been responsible for the implementation of an AMI system along with an outage management system, GIS, SCADA, and an automated staking system. I have also been responsible for the construction management of numerous substations and transmission lines along with upgrading relays and controls at existing substations. During my 30 plus years with utilities, I led storm recovery efforts after ice storms, snowstorms, and hurricanes. My experience includes storm assessment to determine the number of crews required, determination of the areas crews should work so that most consumers have service restored as quickly as possible, working with crews in the field, and post storm review to determine any changes needed.

2023 - Present
President
R. W. Blanton, PLLC
Knightdale, NC

Assist PUCs in Rhode Island and Delaware on rate cases. Assist utilities to analyze events on transmission and distribution lines. Provide forensic engineering and accident investigation services.

	Chief Operating Officer
2020 - 2023	**UtilityEngineering, LLC**
	Raleigh, NC

Responsible for substation design, planning, relay programming, and testing substation relays, assisting with event analysis, and construction. Also, involved in substation commissioning and distribution line design. Work with clients on coordination issues and troubleshooting equipment malfunctions. Performs cost benefit analysis on various construction projects and assists with studies and reports to meet client needs. Assist clients with NERC/FERC requirements.

	Engineering Manager
2017 - 2020	**PowerServices/Pike Engineering**
	Raleigh, NC

Responsible for programming and testing substation relays, assisting with event analysis, substation design, and construction. Work with clients to install and implement grid modernization projects such as automatic distribution restoration systems and micro grids. Performs cost benefit analysis on various construction projects and assists with studies and reports to meet client needs. Completed interconnection agreements on solar projects up to 75 MVA.

	Coordinator of Outside Services
2014 - 2017	**A&N Electric Cooperative**
	Tasley, VA

Coordinate the work of contractors and ANEC crews to upgrade substations due to acquisition of over 20,000 consumers from Delmarva Power. Involved in managing projects at several substations at the same time. I also supervised the Staking Engineers and was also responsible for maintenance of the distribution equipment throughout the system. Assisted with development of a maintenance work plan to complete the required maintenance in the most cost-effective method. Additionally assisted Accounting Department with improvement of the warehouse and CPR systems. Assistance with installation of a new AMI System to improve meter reading and a new SCADA system as part of a substation upgrades.

	Distribution Engineer
2013 - 2014	**NRECA International**
	Pakistan

Worked with the distribution utilities in Pakistan to improve system reliability, metering capabilities with the use of an AMI system, install new meters, and improve the voltage drop and power factor throughout the systems.

Manger of Engineering
2000 - 2013 **Piedmont Electric Membership Corporation**
Hillsborough, NC

Managed Engineering Department of 21 employees, with responsibility for Long- and Short-Range Planning, staking for new services and system upgrades, mapping, dispatching, and substation and transmission line construction and maintenance. Completed 4-year Construction Work Plans in accordance with RUS requirements. During my employment, PEMC implemented an automated metering system (Landis & Gyr), and an automated staking system, as well as installation of a Volt/VAR system to assist in peak load reduction. Was additionally responsible for compliance with NERC and SERC Reliability Standards. PEMC serves over 32,000 consumers in 6 counties.

Director of Electric Utilities
1982 - 1987 **City of Morganton**
Morganton, NC

Managed all aspects of the Electric System for a municipal system of 7,000 consumers.