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Rhode Island Energy™
a PPL company

June 30, 2023

VIA ELECTRONIC MAIL

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

RE: Docket No. 22-49-EL-The Narragansett Electric Company d/b/a Rhode Island Energy Advanced Metering Functionality Business Case
Responses to PUC Data Requests – PUC Set 7

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company"), attached is the electronic version of Rhode Island Energy's responses to the Public Utilities Commission's Seventh Set of Data Requests in the above-referenced matter, with the exception of PUC 7-10 and PUC 7-14.[1] Pursuant to communications with Commission counsel, the Commission provided the Company with an extension to file its responses to PUC 7-10 and PUC 7-14 until July 7, 2023.

This filing includes a Motion for Protective Treatment of Confidential Information in accordance with Commission Rules of Practice and Procedure 1.3(H)(3) and R.I. Gen. Laws § 38-2-2(4) for portions of the responses to PUC 7-16, PUC 7-21, and PUC 7-22 and the attachment to request PUC 7-25, which contain confidential and proprietary business information. For the reasons stated in the Motion for Protective Treatment, the Company seeks protection from public disclosure of portions of the responses to PUC 7-16, PUC 7-21, and PUC 7-22 and Attachment PUC 7-25. Accordingly, the Company has provided the Commission with an original and two complete, unredacted copies of the Confidential responses to PUC 7-16, PUC 7-21, and PUC 7-22 and Confidential Attachment PUC 7-25-1 in a sealed envelope marked "**Contains Privileged and Confidential Information – Do Not Release**," and has included a redacted version of the responses to PUC 7-16, PUC 7-21, and PUC 7-22 and Attachment PUC 7-25 for the public filing.

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

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

Very truly yours,

Jennifer Brooks Hutchinson

Enclosures

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

CERTIFICATE OF SERVICE

I certify that a copy of the within documents was forwarded by e-mail to the Service List in the above docket on the 30th day of June, 2023.

Adam M. Ramos, Esq.

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

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STATE OF RHODE ISLAND

RHODE ISLAND PUBLIC UTILITIES COMMISSION

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

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

The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company") respectfully requests that the Rhode Island Public Utilities Commission ("PUC") provide confidential treatment and grant protection from public disclosure to certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by Rule 1.3(H)(3) of the PUC Rules of Practice and Procedure, 810-RICR-00-00-1-1.3(H)(3) ("Rule 1.3(H)"), and R.I. Gen. Laws § 38-2-2(4)(B). Specifically, the Company requests confidential treatment of limited portions of its responses to PUC 7-16, PUC 7-21, and PUC 7-22, and Confidential Attachment PUC 7-25 , all of which the Company has filed contemporaneously with this motion as part of its responses to PUC Data Requests Set 7. The Company also requests that, pending entry of a ruling on this motion, the PUC preliminarily grant the Company's request for confidential treatment pursuant to Rule 1.3(H)(2).

I. BACKGROUND

On November 17, 2022, Rhode Island Energy submitted its Advanced Metering Functionality Business Case (the "AMF Business Case") in the above-captioned docket. On June 16, 2023, the PUC issued its seventh set of data requests to the Company. The Company's responses to PUC 7-16, PUC 7-21, and PUC 7-22, and Confidential Attachment PUC 7-25 contain confidential and proprietary information (the "Confidential Information") that is exempt from disclosure under APRA. To the greatest extent possible, the Company has protected its confidential interests with limited and targeted redactions.

A. Information Contained in the Company's Responses to PUC 7-16, PUC 7-21, PUC 7-22, and Confidential Attachment PUC 7-25

The Company's Responses to PUC 7-16, PUC 7-21, PUC 7-22, and Confidential Attachment PUC 7-25 contain certain confidential commercial, financial, and proprietary information sourced from vendor agreements, including the same information that the Company redacted in the confidential attachments submitted with the Company's Responses to PUC 6-3 and PUC RR-1. Specifically, the confidential information relates to Confidential Attachments PUC 6-3-1, PUC 6-3-2, PUC 6-3-3, and PUC 6-3-4 and contains specific dollar amounts and percentages that have not been disclosed with the same level of granularity elsewhere in the Company's AMF Business Case. The information is commercially sensitive to the Company's vendors, and the Company and its vendors typically do not disclose this information to the public. Likewise, Confidential Attachment PUC 7-25 is an amendment to the Implementation Statement of Work ("Implementation SOW") Agreement with Tata Consultancy Services ("TCS"), and the original agreement was submitted as Confidential Attachment PUC 6-3-4. The redacted information in Confidential Attachment PUC 7-25 is commercially and competitively sensitive to the vendor because it contains itemized pricing data that is not disclosed with the same level of granularity elsewhere in the Company's AMF Business Case. If this information were disclosed publicly, the vendor's competitors would have the vendor's exact services and product pricing data. Price information is contained in the table of pricing in Section 7 (Pricing) of the Implementation SOW, and Confidential Attachment 7-25 states that, that table be "deleted in its entirety and replaced with" the amended table. The Company has reviewed this attachment and redacted only those portions necessary to protect the third-party vendor's confidential and proprietary information, consistent with the PUC's prior guidance with respect to confidentiality issues. The information for which the Company seeks confidential treatment has been identified by the third-party vendor as confidential and proprietary commercial or financial information.

The Company also seeks confidential treatment for the redacted incremental payments discussed in the Company's responses to PUC 7-16, PUC 7-21, and PUC 7-22. This Confidential Information is the same information that the Company redacted in the confidential attachments submitted with the Company's Responses to PUC 6-3 and PUC RR-1.

II. LEGAL STANDARD

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

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

III. BASIS FOR CONFIDENTIALITY

The Confidential Information contains "trade secrets and commercial or financial information" such that the information does not fall within APRA's definition of a public record. *See* Gen. Laws § 38-2-2(4)(B); *Kane*, 577 A.2d at 663.

The Company's Responses contain excerpts of confidential information, mostly pricing information, that was previously submitted to the PUC and for which the Company requested confidential treatment. Specifically, the Company's Responses to PUC 7-16, PUC 7-21, and PUC 7-22 state specific dollar amounts and percentages related to the payment terms and schedules the Company has with its vendors. This information has not been disclosed with the same level of granularity elsewhere in the Company's AMF Business Case. The information is commercially sensitive to the Company's vendors, and the Company and its vendors typically do not disclose this information to the public.

Similarly, Confidential Attachment PUC 7-25 incorporates the vendor's actual fee structures and unit pricing, which the Company has taken great lengths not to have disclosed elsewhere in the AMF Business Case. The information regarding service fees, cost allocation, and pricing information falls squarely within the APRA exemption. Public disclosure of this line-item detailed information would allow TCS's competitors to easily undercut the vendor's pricing information, which is its main competitive advantage. As the Company has explained, TCS typically does not make this detailed pricing information available publicly, and the Company likewise keeps this information about its vendors confidential. Accordingly, this information is financial information exempt from APRA.

The proposed protections are narrow. The Company seeks to use redactions to protect from public disclosure those limited portions of these attachments that contain proprietary and commercial information. All of the redacted information in the Company's Responses to PUC 7-16, PUC 7-21, and PUC 7-22 and Confidential Attachment PUC 7-25 qualifies for APRA's exemption for "trade secrets and commercial or financial information." R.I. Gen. Laws § 38-2-2(4)(B).

Therefore, Rhode Island Energy respectfully requests that the PUC grant protective treatment to the portions of the Company's Responses to PUC 7-16, PUC 7-21, and PUC 7-22 and Confidential Attachment PUC 7-25 identified by the redactions, and take the following actions to preserve their confidentiality: (1) maintain the Company's Responses to PUC 7-16, PUC 7-21, and PUC 7-22 and Confidential Attachment PUC 7-25 as confidential indefinitely; (2) not place the Company's Responses to PUC 7-16, PUC 7-21, and PUC 7-22 and

Confidential Attachment PUC 7-25 on the public docket; and (3) disclose the Company's Responses to PUC 7-16, PUC 7-21, and PUC 7-22 and Confidential Attachment PUC 7-25 only to the PUC, its attorneys, and staff as necessary to review this docket.

IV. CONCLUSION

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

Respectfully submitted,

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

By its attorney,

____
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Dated: June 30, 2023

CERTIFICATE OF SERVICE

I hereby certify that on June 30, 2023, I sent a copy of the foregoing to the service list by electronic mail.

*/s/ Adam M. Ramos*______

PUC 7-1

Data Requests Regarding June 13, 2023 Technical Session

Request:

Please indicate which peers of Rhode Island Energy are using AMF data for system-wide utility operations.

a. For purposes of this question, please ignore locational pilots.

b. Please provide the network type and communications type, if known.

c. What functions are being executed by those utilities (for example, the Figure 6.1 functions delineated as OPS)?

Response:

(a) through (c)

For this response, Rhode Island Energy's peers include large investor-owned utilities that have fully deployed first or second generation AMI in recent years or are in the process of deploying them. First generation AMI functionality has included the ability to receive utility hourly or quarter-hour energy data for remote meter reading and customer portal development and to provide additional capabilities such as communication of meter health status, outage alerts for proactive outage management, and the ability to remotely disconnect / reconnect power at the meter. These capabilities are enabled by a two-way communication system as a local area network that uses RF mesh and / or point-to-point wireless network systems. First-generation automated metering systems utilize residential data that is generally based upon 15, 30- or 60-minute intervals that is often collected 4-6 times per day.

Second generation AMI systems have advanced RF communication network capability that can be enhanced with Wi-SUN to relay necessary and timely information and alarms from grid-edge intelligence at the meter to the Headend and make it available in near real time. They are typically designed to collect 15-minute interval data every 15 minutes, which ConEd initiated in New York and other utilities are replicating, such as National Grid's operating companies in Massachusetts and in New York. Wi-SUN is being adopted in 2.0 deployments in the US to achieve high performance RF network communications that is standards-based. The adoption is occurring after being fully embraced elsewhere such as Tokyo Electric Power Company in Japan.[1]

Below is a matrix that identifies a representative sample of Rhode Island Energy's peer utilities and the operational functionalities, as defined in Figure 6.1, that have been deployed system-wide:

Peer Utility System-Wide Operational Functionalities

Peer Utility	**Communication Type: Network Type**	**Number Endpoints**	**Proactive Outage Management**	**ADMS Voltage Conservation**	**ADMS Voltage Automated Notification**	**ADMS On-Demand Voltage Measurement**	**Network Model Analysis**	**ADMS DER Monitor and Manage Foundational**
PPL PA Pennsylvania	RF Mesh: 1st Gen	1.5M	Yes	Partial	Partial	Yes	Yes	Partial
ConEd: New York	RF Mesh: 1st Gen	4.7M	Yes	Partial	Partial	Yes	Yes	Partial
ComEd: Illinois	RF Mesh: 1st Gen	4.0M	Yes	Partial	Partial	Yes	Yes	Partial
Liberty Utilities: New Hampshire Arkansas, Oklahoma, Kansas, and Missouri	RF Mesh: 1st & 2nd Gen	700K	Planned /Partial	Planned /Partial	Planned /Partial	Planned /Partial	Planned /Partial	Planned /Partial
FPL: Florida	RF Mesh: 1st Gen	4.6M	Yes	Partial	Partial	Yes	Yes	Partial
PSE&G : New Jersey (approved, deployment underway)	RF Mesh: 2nd Gen	2.3M	Planned	Planned	Planned	Planned	Planned	Planned
National Grid: New York and Massachusetts (approved, deployment underway)	RF Mesh: 2nd Gen with WiSUN	2.3M NY and 1.4M Mass	Planned	Planned	Planned	Planned	Planned	Planned

[1] Smart Utilities - Wi-SUN Alliance: Wi-SUN technology will be included in up to 66 million electricity meters connected to home energy management systems in Japan by 2020.

The operations functionalities in Table 6.1 are defined below. For each functionality a description of what is being done now, largely with first generation AMI systems, and how it is being improved with second generation AMI systems has been noted. Except for the capability of signature recognition, Proactive Outage Management is widely adopted and mature as evidenced by functionality of fully deployed peer systems. The other functionalities are in various stages of maturity, impacted by a range of unique utility attributes including technology selection, investment in data integration, and use of data analytics. For reference, Attachment PUC 7-1 is a white paper by Guidehouse Insights that describes the changes from first to second generation of AMI systems and the impact that localized analytics, which is an important capability that is only available with the second generation AMI, has for the overall value proposition.[2]

Proactive Outage Management

The working definition of Proactive Outage Management is "alerting operations and OMS System when meter experiences an outage or power is restored". AMI deployments commonly have functionality implemented system wide for Proactive Outage Management such as:

- Remote Connect/Disconnect: Utilities see this as a "must have" for AMF deployments because of the cost savings associated with the reduced miles driven (fleet maintenance, fuel, crew time, worker safety, etc.) and as a result, it is nearly unanimously adopted.

- Last Gasp / Power Up: Most utilities have paired AMI data with other data from the outage management system (OMS) to help them determine the extent of the outage, the location of the failure, dispatch prioritization, and ability to send a crew to the location in need of restoration which helping to minimize the duration of the outage.

- On-demand reads: Referred to as a "ping," this functionality is operationally significant and commonly deployed by utilities to determine if an outage is a customer issue (i.e., a tripped breaker) or system issue. Some utilities also send mass pings to meters in an area to identify smaller outages nested within larger outages so crews can verify restoration is complete before leaving an area. Some utilities have developed applications where the dispatcher or the crew can mass

[2] Guidehouse Insights, White Paper, *Inside-the-Meter Intelligence to Become the Norm, How Localized Analytics Is Ushering in a New Era of Sophisticated Home Energy Management and Grid Analytics,* Publ. 3Q 2022.

ping all meters in an area that has experienced an outage to make sure all affected customers have been restored before leaving the area. Similarly, a single or mass ping can also be used for an on-demand voltage measurement or other power quality inquiries.

- Signature Recognition: Machine learning is being used to recognize patterns of messages captured by the meter. The utility can gain insight from this information about the cause and potentially the location of a range of problems. In some cases, these issues are identifiable before the outage occurs, which provides the utility with information to proactively address problems and fix them with scheduled outages before it becomes an emergency. Examples of information that can be gleaned from analytics include transformer oil leakage, voltage, connection issues, secondary connection issues, neutral problems, transformer overloads, and tree interference. Signature recognition will be greatly improved with enhanced measurement capability and with the distributed intelligence hosted in second generation meters.

Comprehensive Voltage Management

The working definition of Comprehensive Voltage Management is "providing interval meter voltage and reactive power data to the ADMS to support conservation voltage reduction (CVR) and Volt-Var Optimization (VVO)". This functionality has been a challenge for first generation AMI deployments primarily due to the communication limitations of the RF network and analytic tools to efficiently digest the voltage data. A survey that ConEd sponsored of utilities that had deployed first generation AMI systems provided insight that the AMI network and systems were initially designed to support billing and were increasingly challenged to meet the real-time requirements of smart grid primarily due to design and technical limitations.[3] Because of the real time network limitations, often voltage data is analyzed in retrospect to identify post event trends to better understand and improve future operation and settings of equipment from a volt-var optimization perspective. Because of real time RF communication network and analytic limitations on first generation systems, an example of a "work-around" to get operational voltage inputs has included using AMI bellwether meters to capture more measurement inputs, where data is brought back from a sample of selected AMI meters on a particular feeder to refine and increase the accuracy of grid optimization algorithms.

[3]ConEdison Advanced Metering Infrastructure Business Plan October 2015.

Second generation AMI, will feature increased sampling capability at the meter, greater analytics and more robust communications that are useful for operators to identify problematic voltage conditions and particular triggers that indicate issues on the system.

Voltage Automated Notification

The working definition of Voltage Automated Notification is "configurable real-time alert for momentary under or over voltage on a meter, integrated into ADMS for immediate action". Because of real-time communication limitations, utilities have been filtering the voltage information that is brought back with the read packets to create reports that capture endpoints with voltages that are too high or too low for further investigation. This approach has been adopted by leading utilities to streamline and proactively mitigate voltage challenges, saving truck rolls and customer frustration associated with voltage complaint investigations as is the case today.

With second generation AMI meters, voltage deviations can be alarmed and more visible to operators. Having the data available in near real time will be important to manage dynamic voltage profiles on feeders that are anticipated with more EV charging and other DERs interconnected with the system.

On Demand Voltage Measurements:

The working definition of On Demand Voltage Measurements is "ADMS functionality to ping networked electric devices and meters for Voltage measurements". This is systematically available now and an adopted practice. More detail is provided with the Proactive Outage Management, above.

Network Model Analytics:

The working definition of Network Model Analytics is "MDMS functionality to support analysis of the network, identifying outlier issues for investigation (e.g. mis- associated meters)". This functionality has been evolving with utilities that have integrated AMI data with other systems and will only improve with second generation capability. For example, for phase balancing, sometimes a meter is not associated with the correct phase of the three-phase distribution system in a network model. As a result of the data mismatch, phase balancing may seem to be needed, however, after investigation, it may not be needed. The reverse can also be true. By aggregating voltage data from the AMI meters and analyzing voltage patterns, potential mismatches can be confirmed and corrected in the Network Model. This process is a best practice example of how network model analytics has been evolving. With second generation capability, anomalies can be identified in near real time and escalated for mitigation in the operations domain, rather than retrospectively by planners.

DER Monitor and Manage:

The working definition of DER Monitor and Manage is "enabling the ability to monitor and manage distributed energy resources (DER) inverter-based infrastructure (e.g., battery banks, solar PV, net-meters)". Most utilities with AMI systems are monitoring the reverse kwh, which, in itself makes it difficult to know how much the DER is generating. With information from the AMF meters and advanced analytics, the native load and generation from the DER can be estimated with a margin of error. The ability to truly integrate DERs with the grid, so they become a contribution with appreciated characteristics, is dependent upon high-speed communications that underlie second generation AMI systems. In spite of first generation AMI communication limitations, PPL Electric in Pennsylvania has been advancing DER Monitoring and Management, through a comprehensive system-wide pilot that allows a direct connection to inverters to monitor and manage them using the IEEE 1547-2018 interconnection standard.

Because of the wide range of technical AMI capability that utilities have adopted, operational adoption of AMI data for DER monitoring and management varies depending upon several factors such as the capability of the RF communication system, and investments that have been made to integrate the DER data and perform analysis. Using AMI for this purpose is currently in its infancy, though it offers significant promise to truly integrate DER contributions and the capabilities of smart inverters with the distribution system. Technology advancements of second-generation AMI systems will greatly improve the capability to perform DER Monitor and Manage due to the edge computing and distributed intelligence that enables grid-facing applications to run directly on the meter. This includes accessing thousands of samples per second to support real-time load disaggregation, utilizing more robust communication networks, and more detailed grid analytics that is enabled by ADMS.

Guidehouse INSIGHTS

White Paper

Inside-the-Meter Intelligence to Become the Norm

How Localized Analytics Is Ushering in a New Era of Sophisticated Home Energy Management and Grid Analytics

Published 3Q 2022

Commissioned by Sense

Michael Kelly
Senior Research Analyst

Laurie Wells
Senior Research Analyst

Introduction

Electric power markets are undergoing a series of massive transformations. From the digitization and decarbonization of global power networks to a revaluation of the role of the end customer, several paradigm shifts are converging with the goal of reshaping the future of the energy industry. The role of smart metering in enabling this transition is critical and absolute. While the first-generation of smart meters have helped to nudge the industry in this direction, the development of second-generation smart meters sets the stage for a rapid acceleration in achieving these goals.

This Guidehouse Insights white paper explores the emerging market for next-generation smart meters. It discusses:

- The evolution of smart meters from a source of data to sophisticated edge-based computing devices
- How advanced analytics and artificial intelligence (AI) applications are being more seamlessly embedded into the advanced metering infrastructure (AMI) hardware and software operating at the grid edge
- The enhanced value proposition in providing real-time, relevant, and actionable insights to customers and grid operators.
- The role of major smart meter manufacturers and analytics providers in enabling these transformations, including Landis+Gyr, Itron, Sense, and others.

Evolution of Smart Metering

An electric meter was originally designed to provide utilities with a simple number—the amount of electric power that flowed through the meter each month. However, the development of new technology and miniaturization of computing power enabled the transformation of electric meter systems into connected networks of intelligent edge computing devices, fully equipped with onboard sensors, computers, and communications capabilities.

Although smart meters vary significantly in their capabilities, for the purposes of this white paper, a smart meter includes the following capabilities:

- Integrated onboard data storage and processing, enabling energy readings at frequent intervals—at least once hourly but often at 15-minute or even more frequent intervals
- Integrated, two-way communications between the meter and a utility’s headend IT systems, enabling remote reading and control (remote disconnect-reconnect) of the meter

Sophisticated next-generation devices, such as Landis+Gyr Revelo, deliver high frequency, high resolution waveform data for utilities and grid operators.

Although these definitions establish baseline technology requirements, advanced smart meters have evolved beyond these rudimentary capabilities. Devices can now measure and monitor the voltage and current waveforms, in addition to total energy, current, and voltage, and can capture these measurements thousands of times per second. This enhanced data availability and resolution is foundational to the enablement of inside-the-meter analytics capabilities that are discussed throughout this white paper.

The Rise of Second-Generation Metering

Nearly all smart meters installed across the globe still classify as first-generation devices. These smart meters lack the technical requirements (sufficient computation, memory, programmability) and data capture capabilities (high resolution waveform data) to constitute second-generation or next-generation devices. Although these embedded capabilities have been a constant source of product evolution since the dawn of AMI, it is only recently that industry-leading manufacturers, such as Landis+Gyr and Itron, have achieved a paradigm-shift-level progression in smart meter technology.

Utilities are constantly searching for ways to create value from their smart meter deployments. While interval data generated by first-generation smart meters has been a valuable input for an array of static and descriptive analytics use cases, the value of certain use cases is hindered by inherent technological limitations. The development of more sophisticated smart meters was born out of the need to provide customers and grid operators with more detailed, real-time information behind-the-meter (BTM) to manage the burgeoning complexities of a more dynamic energy ecosystem. From optimizing the grid through higher levels of situational awareness to more effectively engaging with their customers, many of the macrotrends utilities have chased for years now come a bit easier with the development of second-generation smart meters.

After developing specialized hardware that could be deployed inside electric panels to deliver real-time data streams, Sense and others are now working with meter manufacturers in order to deploy these technologies at scale, as its more logical to embed this functionality into existing infrastructure at the home; more specifically, at the meter.

The ability to capture high resolution current and voltage waveform data, which was previously only possible with additional hardware, is revolutionary. The analysis of waveform data enables device and pattern recognition capabilities in real time, capabilities that are not available with existing on-premise or cloud-based architectures. High resolution waveform data and edge computing enable new applications to be run inside the meter itself.

From Data Source to Edge-Based Computing Device

It’s been established that the next generation of smart meters can capture massive amounts of data across several parameters (i.e., current and voltage waveform data). The question then becomes, so what? This treasure trove of data is essentially useless if not properly acted upon; the underutilization of smart meter data in helping customers make their homes smarter and more efficient, as well as the underinvestment in analytics, is something that has plagued the utility industry for years.

However, these barriers erode when presented with next-generation smart meters, such as Landis+Gyr’s Revelo and Itron’s Riva Distributed Intelligence (DI) meters. Improvements in device functionality, along with open ecosystems of analytics partners, creates an architecture in which utilities and their customers can benefit from real-time, actionable insights from intuitive touchpoints (e.g., smartphones, home assistants). Rather than smart meters operating only as a data source, which have been their primary function since the invention of electromechanical meters in the 1800s, the next generation of smart meters can operate as truly sophisticated edge computing devices.

To summarize, three capabilities are required to turn smart meters into powerful edge computing devices:

1. High resolution waveform data with sample rates capable of enabling real-time device identification (at least 15,000 samples per second).

2. Edge computing in the meter itself that has access to the raw data stream.

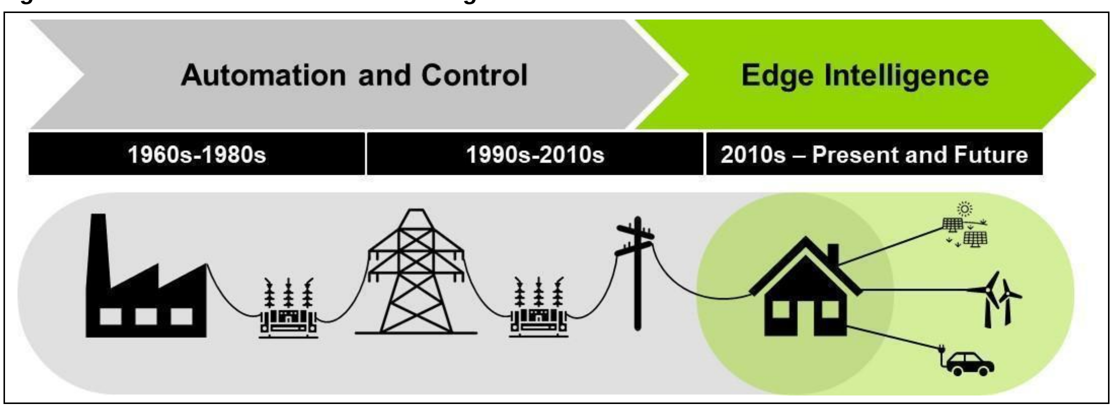
3. Low latency networking via Wi-Fi or cellular to support real-time consumer experiences (with delays within one or two seconds).

Enabling the Next Generation of Energy Analytics

Prior to the technological advancements led by Landis+Gyr and Itron, there was little to no value in performing smart meter analytics at the edge, i.e., inside-the-meter, as the same insights could be generated by performing this analysis in the back office. The current set of smart meter analytics solutions on the market primarily use low resolution data and static reporting techniques to deliver descriptive insights. This has fostered a perception across the industry that these types of solutions provide limited operational value for utilities and their customers. However, the metering foundation discussed throughout this white paper debunks these traditional lines of thinking and redefines the potential value of smart meter analytics moving forward.

The newest generation of smart meters provides a viable solution to the computing and data resolution issues that have inhibited the adoption of inside-the-meter analytics, and true edge computing, to date. Figure 1 illustrates the extension of monitoring and control capabilities across transmission and distribution networks, culminating in the proliferation of distributed intelligence at the grid edge.

Figure 1. The Evolution of Grid Intelligence



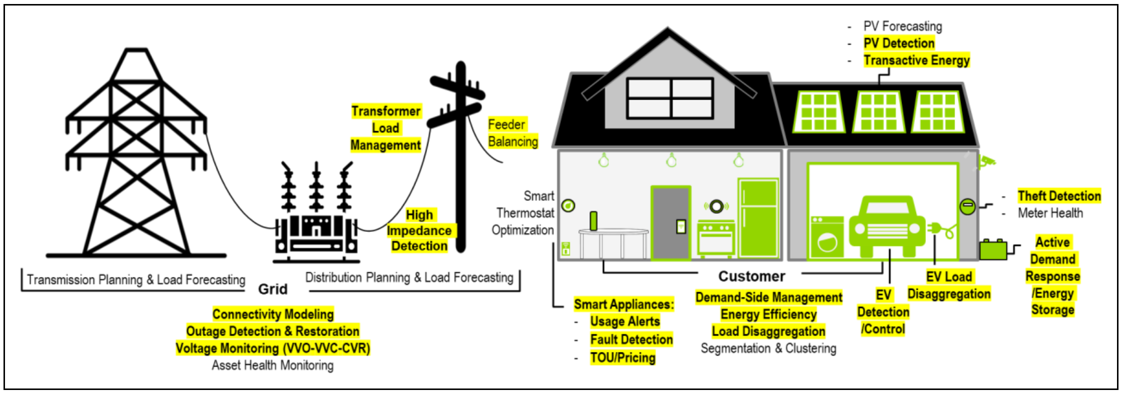
(Sources: Guidehouse Insights)

Where use cases demand real-time intelligence, such as notifying a customer that they have activated an appliance or electric vehicle (EV) during a higher priced time interval or sending real-time notifications regarding detected faults and anomalies, the logical solution is to tap into analytics engines on the meter itself. Moving raw, high resolution waveform data through the cloud would be cost-prohibitive, with latency constraints further deflating the relative value of these respective use cases.

Growing List of Grid and Customer Applications

This section discusses the primary applications used to deliver inside-the-meter intelligence to utilities and their customers. Figure 2 illustrates the wide range of smart meter analytics applications that have been developed to date, while highlighting the subset of use cases that can be supported inside-the-meter.

Figure 2. Inside-the-Meter Intelligence Applications



(Sources: Guidehouse Insights)

Although the list of available localized analytics applications spans several segments, the impact of these next-generation devices in enhancing home automation & energy management and grid management are discussed in more detail below.

Home Automation and Energy Management (BTM)

Smart meters have proved valuable tools for utilities in engaging with their customers since the dawn of home energy reports. Many utilities already offer their customers daily or monthly energy usage information and insights regarding their bill. Yet the majority of these applications have focused on engaging customers from a solely energy management perspective rather than the broader position of overall intelligence for the home. This is largely due to the data resolution constraints of first-generation smart meters and the latency constraints of traditional on-premise and cloud-based analytics architectures. Embedding AI-powered algorithms into next-generation smart meters enables new capabilities around device recognition, real-time usage tracking, and proactive notifications, that support greater benefits around home automation, customer experience, energy management, and more.

To support this broader range of customer- and home-oriented use cases, advanced solutions providers such as Sense use high resolution energy monitoring and machine learning algorithms to provide detailed real-time insights into how devices are being used right now. Customers can watch on an app as they turn on and off the stove or plug and unplug devices, seeing in real time how these actions translate into energy consumption; the app can also provide alerts, for example, if the stove has been left on too long, promoting safety benefits.

This high resolution, real-time approach to delivering customer insights has been proven to facilitate higher levels of customer engagement over traditional home energy management (HEM) methods. Interacting and engaging with customers in real time can also facilitate benefits on the utility side of the meter, including enabling new channels for energy efficiency resource procurement, enhancing demand flexibility for demand response (DR) programs, and facilitating tighter integration and control of new electrified loads (e.g., EVs) on behalf of customers. These sophisticated platforms create a bridge between consumers and utilities at the intersection of the smart home and the grid.

Grid Management and Optimization (Front-of-the-Meter)

High resolution waveform data streams and edge-based computing can also be leveraged to support a broad range of asset- and network-oriented use cases.

With the development of AI-based connectivity modeling algorithms, new location-based (spatial) analytics can deliver near-real-time visibility of network connectivity across meters, transformers, and feeders, based on smart meter data. For example, Landis+Gyr and Itron second-generation devices offer connectivity information and electrical location for every smart meter on the network. These enhanced spatial capabilities (i.e., connectivity information) work in concert with high resolution waveform data streams to facilitate new and improved grid management applications. This information can be used to help grid operators pinpoint outages for quicker power restoration, geolocate unpredictable loads, identify and integrate distributed energy resources, and detect voltage and other power anomalies.

One of the major enablers of these upstream applications is waveform analysis. Emerging localized analytics algorithms can examine waveform data captured by smart meters to identify power quality characteristics both BTM and in front-of-the-meter (FTM). The combination of waveform analysis, connectivity information, and peer-to-peer communications enables grid operators to understand, with a high degree of accuracy, the when (has an outage occurred?), where (location on the distribution system), and what (fault type) of fault occurrences. This allows utilities and grid operators to know what type of crew to roll out and facilitates higher mobile workforce efficiencies and enhanced asset and outage management practices. Customers simultaneously benefit from quicker power restoration and minimized outage times.

While a subset of second-generation smart meters promotes near-real-time data capture capabilities, sophisticated next-generation devices, such as Landis+Gyr Revelo, go beyond sub-second in delivering high resolution waveform data streams. While it may seem like a trivial distinction to some, this delineation can have a significant impact on the accuracy and level of insights delivered to grid operators responsible for management and control at the grid edge.

Inside-the-Meter Intelligence to Become the Norm

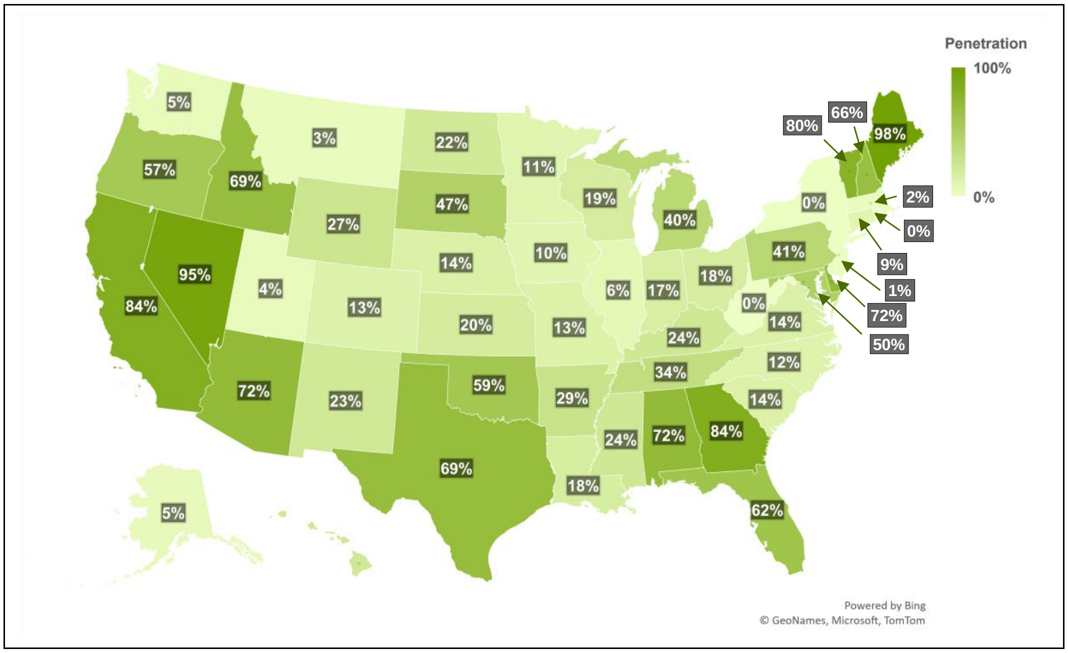
The transition to inside-the-meter analytics is reminiscent of the transformation witnessed in the telecom space with the proliferation of smartphone devices. That sector saw a radical and rapid transition from consumers using phones the way they had been for decades, to using smartphones as computation and application platforms. For example, if a consumer had wanted a music player or navigation system, they would need to purchase a separate piece of hardware to perform that specialized function; with the emergence of smartphones, an entire new market for applications was created due to transformational improvements in device architectures and capabilities. The same can and should happen with energy infrastructure, with the electric meter sitting at the heart of this paradigm shift.

The share of second-generation smart meters in the US is expected to grow from approximately 4% in 2021 to more than 25% by 2030.

Although the market for second-generation smart meters is still nascent, it is not expected to remain so for very long. Industry-leading smart meter manufacturers, such as Landis+Gyr and Itron, have shifted their strategies to promote next-generation devices as their newest flagship offerings. Supplemented by the negligible difference in price between first- and second-generation smart meters, along with the host of benefits and value potential highlighted earlier, it's logical to expect the next wave of smart meter upgrades to primarily involve second-generation smart meters. The combination of supply- and demand-side drivers position these sophisticated devices for overwhelming success moving forward.

The evolution in smart meter technology is also quite timely; when examining the smart meter landscape across North America and Western Europe, there is a massive base of smart meters set for upgrade and replacement over the coming decade. This is due to the initial surge in smart meter installations experienced during the late 2000s and early 2010s; subsidies offered under the US Smart Grid Investment Grant and European Union (EU) Directives programs beginning in 2009 galvanized the US and European smart meter markets. Figure 3 illustrates this in the form of a US heatmap of early-stage smart meter penetration, with several states already reaching more than 50% customer penetration by the end of 2013.

Figure 3. Smart Meter Penetration, US: 2013



(Source: Guidehouse Insights)

Although vendor specifications typically cite the lifespan of smart meters at 20 years, this is largely overestimated, as technology obsolescence and security issues are forcing replacement rates between 12 and 15 years. Based on a jurisdiction scan of Guidehouse Insights' *Global AMI Tracker*, shown in Table 1, the average lifespan of first-generation smart meter deployments is approximately ~12 years. Several factors will ultimately determine meter lifespans, such as weather conditions, availability of new technologies, analytics roadmaps, and communications requirements.

Table 1. Smart Meter Lifespans by Utility

Region & Utility	Logo	Meter Lifetime	Key Insights
North America	**N/A**	**Years**	**Description**
Arizona Public Service	aps	2 - 7 Years	Arizona Public Service installed its first-generation smart meters between 2007 and 2014. The utility began deploying second-generation smart meters as early as 2 years following the initial deployment (e.g., Sedona, Verde Valley), while some meters were replaced after 7 years (Phoenix area).
EnergyUnited	EnergyUnited	~10 Years	EnergyUnited installed its first-generation smart meters between 2009 and 2012. The utility began deploying smart meters as part of its second-generation upgrade deployment in September 2020.
GreyStone Power	GreyStone	~13 Years	GreyStone Power installed its first-generation smart meters in 2007. The utility is deploying smart meters as part of its second-generation upgrade deployment from 2020-2023.
Pedernales Electric	PEC	~17 Years	Pedernales Electric installed its first-generation smart meters beginning in 2003. The utility is deploying Aclara smart meters as part of its second-generation upgrade deployment that began in 2021.
PPL Electric	ppl	~12 Years	PPL Electric finished its initial AMI deployment in 2004. The smart meter replacement project began in December 2016 and was completed in 2019.
Salt River Project	SRP	~11 Years	SRP completed its first-generation smart meter deployment in 2013. The utility is set to complete its second-generation upgrade deployment in 2024.
Western Europe	**N/A**	**Years**	**Description**
Enel – Italy	enel	~15 Years	Enel installed its first-generation smart meters between 2001 and 2006. The utility began deploying Enel smart meters as part of its second-generation upgrade deployment in 2017.
E.ON – Sweden	e.on	~10 Years	E.ON installed its first-generation smart meters between 2006 and 2009. The utility began deploying Landis+Gyr smart meters as part of its second-generation upgrade deployment in July 2019.
Ellevio – Sweden	ELLEVIO	~12 Years	Ellevio installed its first-generation smart meters between 2007 and 2009. The utility began deploying Sagemcom smart meters as part of its second-generation upgrade deployment in September 2020.
Vattenfall – Sweden	VATTENFALL	~15 Years	Vattenfall completed its first-generation smart meter deployment in 2008. The utility began deploying smart meters as part of a two-phase second-generation upgrade project; set for completion in 2022 and 2025, respectively.
Elenia – Finland	ELENIA	~15 Years	Elenia installed its first-generation smart meters between 2004 and 2008. The utility began deploying Aidon smart meters as part of its second-generation upgrade deployment in mid-2020.

(Source: Guidehouse Insights)

In the US, approximately 37 million smart meters will be 12 years old or more by 2023, and nearly 65 million by the end of 2027.

This implies that over the course of the next decade, the US, as well as pockets of Western Europe, will experience a similar surge in upgrade and replacement projects, reminiscent of the first wave of smart meter installations during the 2010s. This anticipated upgrade trend is already playing out in some areas, with a growing number of utilities having selected or installed next-generation devices as part of their second-generation smart meter deployments.

Vendor Approaches to Inside-the-Meter Analytics

At the forefront of this transformation are a combination of smart meter manufacturers and growing ecosystems of analytics providers. These companies have been early movers in the development of enabling technologies and have continued to innovate in their quest for market leadership. Among smart meter manufacturers, two major providers have led the way, Landis+Gyr and Itron:

- **Landis+Gyr** is making inroads in the space with its Revelo line of smart meters. Combining edge computing and waveform data processing technologies, Landis+Gyr's next-generation meters enable real-time pattern recognition of energy delivery, including HEM, fault identification, and safety-based use cases. The ability to capture not just sub-second data streams but high resolution waveform data is a key differentiating feature that positions Landis+Gyr and its analytics providers for success moving forward. The company has attracted a flurry of second-generation smart meter wins over the course of 2020 and 2021, including 1.7 million meters in National Grid's New York service area.

- **Itron** has been developing its portfolio of inside-the-meter applications for nearly a decade. In October 2014, Itron released Riva, its open distributed computing platform. Now branded

Distributed Intelligence (DI), this platform supports applications for meter bypass detection, location awareness, high impedance detection, residential neutral fault detection, transformer load management, solar awareness, active premise load shedding, and many others. More than four million Itron Riva DI meters have been deployed to date with nearly four million licensed applications in use.

While next-generation smart meters provide the enabling hardware behind inside-the-meter intelligence, the development of AI-enabled software applications has been led by open ecosystems of analytics partners. There are a growing number of innovative companies operating across the continuum of inside-the-meter application development, including Sense, Grid4C, and Utilidata, among others.

Sense has worked with Landis+Gyr to embed its high resolution processing software application into Revelo meters; this follows Landis+Gyr's purchase of a small equity stake in the company in January 2019. Sense pioneered working with high resolution waveform data streams and delivering real-time insights through its flagship home energy monitors. But where Sense has historically relied upon additional hardware for high resolution data capture, under the Landis+Gyr partnership, the company now offers embedded analytics applications that can be activated on any Landis+Gyr Revelo meter, without the additional hardware expense. In such a nascent space, Sense is unique in its ability to bring proven expertise to the table in leveraging high resolution waveform data streams across energy, current, and voltage, for the delivery of real-time, actionable insights to drive customer engagement.

Grid4C, meanwhile, is embedding its GridEdgeAI software within Itron's Riva equipment to help customers monitor appliance-level usage and issue proactive notifications. Similarly, Landis+Gyr partnered with Utilidata to deploy energy optimization software within Revelo meters, enabling several grid-based use cases (e.g., fault detection, feeder monitoring).

Conclusion

Ultimately, the stage is set for the proliferation of second-generation smart meters over the next decade and beyond. In terms of market demand, the negligible price difference between first- and second-generation devices, supported by the array of benefits highlighted throughout this white paper, makes these sophisticated smart meters the clear and logical choice for both new and replacement projects moving forward. In terms of market supply, aggressive development and strategic marketing from leading smart meter manufacturers, complemented by rich and growing ecosystems of impressive analytics partners, is forcibly nudging the smart meter market in the direction of next-generation technologies.

The value proposition behind smart meter deployments has yet to be fully realized. Immediate benefits around workforce optimization, billing accuracy, and outage detection represent the tip of the iceberg in potential value creation. This paradigm shift in edge computing functions to not only deliver enhanced benefits to utilities and their customers, but also supports larger climate and decarbonization goals. From using high resolution data from the edge to assist in the deployment and management of new electric loads (namely EVs) to leveraging real-time customer experiences for better calibration of demand- and supply-side resources, the value stacking potential of inside-the-meter intelligence permeates all facets of the energy ecosystem. The edge intelligence enabled by next-generation metering technologies provides real-time visibility to unprecedented data streams to deliver value both BTM and FTM—helping utilities, customers, and society-at-large to better manage energy for a brighter future.[1]

[1] Revelo Meters Overview, Landis+Gyr, https://www.landisgyr.com/product/revelo-meters.

Acronym and Abbreviation List

AI	Artificial Intelligence
AMI	Advanced Metering Infrastructure
BTM	Behind-the-Meter
DI	Distributed Intelligence
DR	Demand Response
EU	European Union
EV	Electric Vehicle
FTM	Front-of-the-Meter
HEM	Home Energy Management
IT	Information Technology
US	United States

Table of Contents

Scope of Study

Guidehouse Insights prepared this white paper, commissioned by Sense, to explore how innovative applications of advanced analytics and AI are helping utilities maximize the value of their AMI investments. It provides an overview of smart meter analytics and discusses the evolution of more sophisticated architectures operating at the grid edge, helping provide more timely, relevant, and actionable insights for customers and grid operators.

Published 3Q 2022

PUC 7-2

Data Requests Regarding June 13, 2023 Technical Session

Request:

At the technical session, Commission staff was trying to determine what is necessary to enable critical peak pricing and peak rebate pricing. Please confirm that the necessary components include (1) interval metering to determine how much energy a customer used during the event; and (2) there needs to be a way to tell customers prior to the event that an event will be called. If this is accurate, please explain why, if at all, higher speed communication on the network enhances these rate design options.

Response:

Yes. The Commission staff is correct that the necessary components for critical peak pricing and peak rebate pricing do include interval metering and there needs to be a way to communicate to customers prior to the event. Historically, these rate designs have been implemented without a high-speed communication system; however, by using high speed communication network that offers near real time data, the rate design options can be greatly enhanced. A high speed network has the capability to communicate varying prices and apply incentives that vary when rates are available which, especially when used together, are inherent to complex TVR rate design useful to incentivize timely behavior adjustments to optimize the grid as operations become increasingly dynamic and uncertain. Without a high-speed communication system, the near real time visibility is not available to the customer or the utility in a manner that effectively permits variable application of incentives, therefore limiting offerings to simple TVR rate designs. The near real time visibility makes it possible for customers to respond to variable rates and adjust their energy usage so that the TVR rate designs are effective in reducing load. Simplified TVR may not be sufficient given the highly variable system conditions that can result from increased DER and EV charging.

Additionally, near real time information enabled by a high-speed network provides the wherewithal for timely evaluation, measurement, and verification of the actions that customers have taken. Having the ability to verify and measure where and when demand reduction has occurred in near real time will improve the effectiveness and the efficiency of the rate design because there will be increased confidence and certainty of the contributions from them. Without the near real time capability, neither the customer nor the utility has the visibility or feedback of the actual demand response impact during the specific critical peak hours. The utility also does not know where on the system the demand reductions are taking place.

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

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PUC 7-3

Data Requests Regarding June 13, 2023 Technical Session

Request:

As an alternative to critical peak pricing, could Connected Solutions be modified and scaled using the meters without the high-speed network? Please explain.

Response:

Hypothetically, it is possible that Connected Solutions could be modified and scaled to become an alternative to Critical Peak Pricing ("CPP"); however, the Company believes that it would be extremely difficult to modify and scale Connected Solutions to do CPP, regardless of the speed of the network. Scaling the Connected Solutions program would necessitate a complete redesign of the program to mimic what is envisioned in the CPP benefit calculation

Regarding the speed of the network, the purpose of CPP is to be able to adjust demand during those critical hours of the year when the system is extremely stressed. The CPP time periods are typically 3-4 hours. Implementing CPP with a four-to-six-hour delay, as would be the case without the high-speed network, would eliminate the visibility needed by the operators during those critical hours. In addition, while currently there are approximately 20-30 critical hours of the year, in the future the Company anticipates many more critical hours where the load will need to be adjusted, either higher or lower, making the high-speed network that much more important.

Below is a description of the current Connected Solutions program and how it would need to be modified to accommodate CPP.

Currently, Connected Solutions is a voluntary demand response rebate program that has been designed to reward customers for reducing their electricity use during periods of high demand. In exchange for rebate incentives, customers allow Rhode Island Energy to control their enrolled thermostats, batteries and solar inverters per the terms specified in the program. Upon enrollment, the vendor gains remote access to adjust device settings through a Wi-Fi connection. The vendor, rather than the customer, performs the action of adjusting settings for enrolled devices during peak time events.

Expanding the Connected Solutions program to administer a CPP program would require a new AMF meter, regardless of the speed of the network. The incentive mechanism for the Connected Solution program would need to be changed such that savings to the customer would be made available based upon the actual demand reduction that is realized and measured by the AMF meter for the entire home, including any Electric Vehicles (EVs) present; it would also need advanced analytics that would be performed in the back office after the peak event. The modified Connected Solutions approach discussed herein contrasts to the existing offering today because an incentive is provided for results achieved as compared to providing a flat seasonal rebate for thermostats and solar inverters that is independent of the actual demand reduction realized. The following are additional considerations for modifying and scaling Connected Solutions:

(i) The Company administers Connected Solutions via a vendor, Energy Hub. Energy Hub manages program enrollment (which is automated through an API), active management and communications of devices, calculation of payments, and sending payments to participants. Because Connected Solutions is implemented by an external vendor, compensation for participation comes from that vendor; it is not integrated into customer bills. Modifying Connected Solutions to offer whole house CPP would mean that the CPP price signal is separate from the customer's bill.

(ii) Currently, there are less than 1% of residential customers participating in Connected Solutions. The Company is assuming 20% residential participation in opt-in CPP, so Connected Solutions would need to be scaled more than 20-fold. Scaling would necessitate a revised contract, inclusive of incremental costs for program administration.

(iii) Connected Solutions currently only allows limited technology participation: eligible thermostats, solar inverters, and battery energy storage systems. Modifying Connected Solutions to be able to account for whole house performance would necessitate associated metering that collects interval data that is used in conjunction with a slower speed network to collect the data, every four to six hours, which could be done using the proposed meters with or without the high-speed network.

(iv) As Connected Solutions is currently administered, payments for participating thermostats and solar inverters are independent of performance; only battery energy storage systems are compensated based on performance. AMF meters would allow for payment based on performance with or without the high-speed network, and Connected Solutions would likely be able to accommodate this based on its ability to compensate for performance for batteries as proof of concept.

PUC 7-4

Data Requests Regarding June 13, 2023 Technical Session

Request:

In Pennsylvania, can a customer who is on competitive supply opt into time of use rates?

Response:

No, a customer who chooses competitive supply in Pennsylvania cannot elect PPL Electric Utilities Corporation ("PPL Electric") time of use rate. A customer who chooses competitive supply may opt-in to time of use rates if available from a competitive supplier in the market.

Prepared by or under the supervision of: Bethany L. Johnson, Philip J. Walnock, and Wanda Reder

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PUC 7-5

Data Requests Regarding June 13, 2023 Technical Session

Request:

In Pennsylvania, please confirm that the time-of-use rate applies to all volumetric charges on a customer's bill. If the answer is not yes, please set forth all the charges on the Pennsylvania bill to which time-of-use rates apply and which do not. If this is different for a customer taking competitive supply, please explain. Please explain any differences between customer classes that may exist.

Response:

No, PPL Electric Utilities Corporation's ("PPL Electric") time-of-use rate does not apply to all volumetric charges on a customer's bill. The time-of-use rate applies only to PPL Electric's generation service (similar to Rhode Island Energy's LRS rate) and is available to residential and small commercial and industrial customers. There are no differences between the residential and small commercial and industrial customer classes regarding how PPL Electric applies its time-of-use rate. Attachment PUC 7-5 provides an example of a PPL Electric customer bill showing the application of the time-of-use rate.

Please see the Company's response to PUC 7-4 regarding the availability of PPL Electric's time-of-use rates to customers taking competitive supply. Because a customer taking competitive supply who is on a time-of-use rate offered by their supplier is receiving that rate from their supplier – and not from PPL Electric – PPL Electric and the Company are not aware of the specific elements of the customer's bill to which those time-of-use rates may apply and how they may differ from the application of PPL Electric's time-of-use rate.

Prepared by or under the supervision of: Bethany L. Johnson, Philip J. Walnock, and Wanda Reder

PPL Electric Utilities

We deliver.

1-800-342-5775
For hours of operation and to pay/manage your account, visit pplelectric.com.

Meter Account

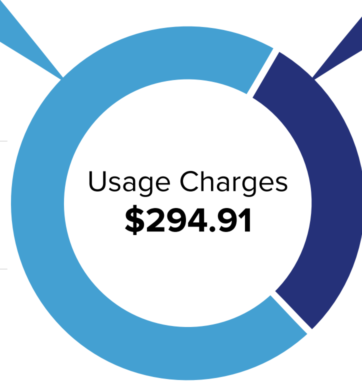
Due Date	Amount Due
6/29/23	$408.19

Service to:

Time-Of-Use Program: The rate varies by the time of day. To save money, shift usage to off-peak hours.

Supply $208.24

Usage from May 9 - Jun 8



$86.67 Delivery

PPL Electric Utilities
1-800-342-5775

Effective Date
12/10/18

PPL Electric Utilities Price to Compare

$0.12126 Use this price when comparing supplier offers.

SHOP FOR ELECTRICITY

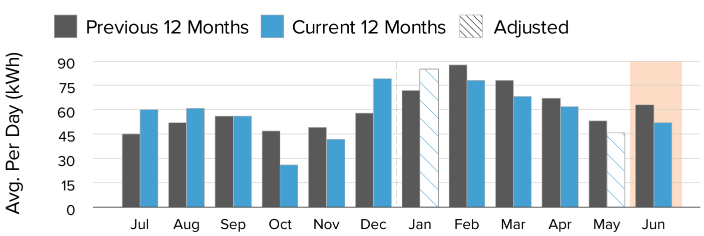
Visit PAPowerSwitch.com or www.oca.state.pa.us
If you're shopping, know your contract expiration date.
Account Number:
The price to compare is updated June 1st and December 1st.
Rate: RS. View schedule at pplelectric.com/rates

PPL Electric Utilities

Consider making a monthly pledge to Operation HELP to assist those in need to heat their homes.

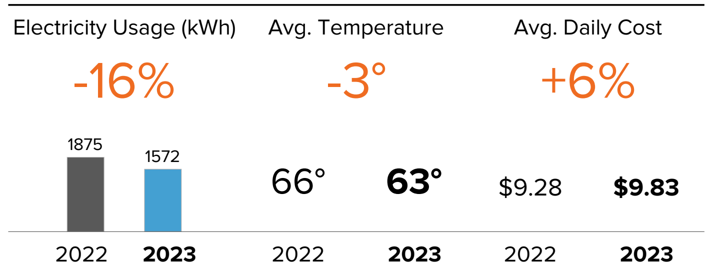
WANT TO SAVE?
Shaded air conditioning units use up to 10% less electricity than if they operate in the sun.

Usage Summary



For usage and billing details, visit us online at pplelectric.com

June



Questions/concerns? Contact us by 6/29/23

1-800-342-5775
Visit pplelectric.com for hours of operation.

PPL Electric Utilities

Correspondence to:
PPL Customer Service
827 Hausman Road
Allentown, PA 18104-9392

Sign back of bill stub to enroll in auto bill pay.

Account Number	Due Date	Amount Due
	6/29/23	$408.19

Amount Enclosed:

Please make check payable to: PPL ELECTRIC UTILITIES
2 NORTH 9TH STREET CPC-GENN1
ALLENTOWN, PA 18101-1175

kWh Delivered (to Customer)			
Meter Number	Reading Dates	Meter Reading	Kilowatt-Hours
	Jun 8	89066	Summer On-Pk: 52 Summer Off-Pk: 315 Winter On-Pk: 150 Winter Off-Pk: 1055
	May 9	87493	

Total Summer On-Pk: 52	Total Summer Off-Pk: 315	Total On-Pk Delivered: 202
Total Winter On-Pk: 150	Total Winter Off-Pk: 1055	Total Off-Pk Delivered: 1370
Days Billed: 30	Avg. kWh/Day: 52	Total Delivered: 1572

Date Range	Annual Total Usage	Avg Monthly
Jul 2022 - Jun 2023	21819 kWh	1818 kWh

Next meter reading on or about: Jul 10, 2023.
State taxes this bill: About $2.86. **PA Gross Receipts Tax:** About $17.39.

Understanding Your Bill

Act 129 Compliance Rider - Monthly charge to recover costs for energy efficiency and conservation programs approved by the PUC.
Customer Charge - The basic service charge to partially cover costs for billing, meter reading, equipment and service line maintenance. If you select a new supplier, the name, address and telephone number for both your distribution and supplier company will appear on your bill.
Distribution Charge (Delivery) - Part of the basic service charges on every customer's bill for delivering electricity from the electric distribution company to your home or business. The distribution charge is regulated by the Public Utility Commission. This charge will vary according to how much electricity you use.
Kilowatt-hour (kWh) - The basic unit of electric energy for which most customers are charged in cents per kilowatt-hour. A kilowatt-hour is the equivalent of using ten 100-watt light bulbs for one hour.

Billing Summary

Previous Balance	$374.03	
Payment Received Jun 6, 2023 - Thank You!	-$374.03	
Balance as of Jun 8, 2023		$0.00
Total Supply Charges		$208.24
Total Delivery Charges		$86.67
Other Charges		
Payment Plan Installment Amount	$113.28	
Total Other Charges		$113.28
Amount Due By **6/29/23**		**$408.19**
Account Balance		$408.19

Delivery Details

PPL Electric Utilities

Distribution Charges	
Residential Rate: RS for May 9 - Jun 8	
Customer Charge	15.86
1,572 kWh at 4.6139¢ per kWh	72.53
Tax Cut and Jobs Act Credit at -8.23%	-5.73
System Improvement Charge at 5.00%	4.13
PA Tax Adj Surcharge at -0.134%	-0.12
Total Delivery Charges	**$86.67**

Understanding Your Bill

kWh Delivered – The amount of electricity we delivered to you for your use.
Rate RSO TOU - Rate for service with year-round time-of-day use.
Summer On-Peak - Rate from 6/1 to 11/30 for on-peak usage from 2-6 p.m. weekdays except holidays.
Summer Off-Peak - Rate from 6/1 to 11/30 for off-peak usage for all hours (except 2-6 p.m.), weekends and select holidays.
Winter On-Peak - Rate from 12/1 to 5/31 for on-peak usage from 4-8 p.m. weekdays except holidays.
Winter Off-Peak - Rate from 12/1 to 5/31 for off-peak usage for all hours (except 4-8 p.m.), weekends and select holidays.
Storm Damage Expense Rider - Monthly charge to recover certain costs to make repairs after major storms.
System Improvement Charge - Monthly charge to recover costs for improving, repairing and replacing equipment that delivers electricity to your home or business.
Smart Meter Rider - Monthly charge to recover costs associated with the smart meter programs approved by the PUC.
State Tax Adjustment Surcharge - Monthly charge or credit to reflect changes in various state taxes. The surcharge may vary by bill component.

Enroll in Automatic Bill Pay

Enroll in Automatic Bill Pay (ABP) and your monthly electric payment will be automatically deducted from your bank checking account. To enroll, sign and date this form and return your check payment (voided check not required). Money orders, cashier and foreign checks do not qualify for enrollment.

I authorize PPL Electric Utilities to automatically deduct from the checking account as shown on my enclosed check, all future payments for the PPL Electric Utility bill account number listed on this payment stub. I will notify PPL Electric Utilities if I decide to cancel this authorization.

To enroll in automatic bill payment, Checking Account holder sign here ______________________ Date ________

Note: To enroll a savings account in automatic bill pay visit pplelectric.com/autopay.

$408.19

PPL Electric Utilities

Account Number	Due Date	Amount Due
	6/29/23	$408.19

Supply Details

PPL Electric Utilities

Generation & Transmission Charges for May 9-Jun 8	
Transmission Charge:	
1,572 kWh at 2.32693¢ per kWh	36.58
Generation Charge:	
Capacity and Energy	
Summer On-Pk:	
52 kWh at 13.269¢ per kWh	6.90
Summer Off-Pk:	
315 kWh at 8.825¢ per kWh	27.80
Winter On-Pk:	
150 kWh at 13.255¢ per kWh	19.88
Winter Off-Pk:	
1,055 kWh at 11.098¢ per kWh	117.08
Total PPL Electric Utilities Charges	**$208.24**

For questions on these charges, please contact this supplier at:

1-800-342-5775

PPL Electric Utilities
Customer Services
827 Hausman Rd
Allentown, PA 18104-9392

General information: Generation prices and charges are set by the electric generation supplier you have chosen. The Public Utility Commission regulates distribution rates and services. The Federal Energy Regulatory Commission regulates transmission prices and services.

Understanding Your Bill - Continued

Transmission Charge - Part of the basic service charges on every customer's bill for transporting electricity from the source of supply to the electric distribution company. The Federal Energy Regulatory Commission regulates retail transmission prices and services. This charge will vary with your source of supply.

Tax Cut and Jobs Act Credit - Monthly adjustment for federal tax changes.

Type(s) of Meter Readings:

Actual - Measures your monthly electricity use based on an actual reading.

Adjusted - Measures your monthly electricity use based on an actual reading but adjusted for the billing cycle.

PUC 7-6

Data Requests Regarding June 13, 2023 Technical Session

Request:

Using the current RI Energy bill components, please explain which would be covered by the Pennsylvania time-of-use rates and whether it would be different for customers on competitive supply. Please explain any differences between customer classes that may exist.

Response:

If Rhode Island Energy applied PPL Electric Utility Company's time-of-use rate to Rhode Island Energy's bill components, only the LRS component would be subject to time-of-use rates. Please see the responses to data requests PUC 7-4 and 7-5 regarding differences for customers on competitive supply and differences between customer classes.

PUC 7-7

Data Requests Regarding June 13, 2023 Technical Session

Request:

What portions of the bill were assumed to be variable in the calculation of time of use benefits in the BCA?

Response:

There were no assumptions made regarding the rate design of either the time-of-use or Critical Peak Pricing rates; the discussion in Section 11.5.5 of the Advanced Metering Functionality ("AMF") Business Case indicated that the specific rate design would be developed through a separate regulatory proceeding. "Rhode Island Energy estimated savings associated with using AMF meters for TVR and has made a commitment to return to the PUC in the future with a proposal for TVR." (Bates, p. 149) Thus, the specifics of the bill impacts also were not determined.

There are four categories of time varying rates that were quantified as part of the AMF BCA. Those four categories are:

1. Whole House Time of Use (TOU).
2. Whole House Critical Peak Pricing (CPP).
3. Electric Vehicle (EV) Time Varying Rate (TVR) energy shift benefit.
4. EV CPP.

The benefits that the Company quantified included the energy shift savings, system capacity savings, transmission and distribution savings and the associated societal benefits related to CO2, NOx, Public Health and Demand Reduction-Induced Price Effects (DRIPE) savings.

The Company calculated Whole House TOU and CPP benefits only for the residential sector and based those estimated benefits on the results of the programs, e.g., a 3.7% reduction in on-peak usage for TOU and a 1.6% increase in off-peak usage for TOU and, for CPP, a 20% reduction of the residential contribution to the system peak.

The Company calculated the Electric Vehicle TOU and CPP benefits based on the number of EVs without regard to whether they were owned by residential, commercial or industrial customers. The EV TVR energy shift benefit applied the differential between the on-peak price and the off-peak price to the number of kWh shifted. The EV Critical Peak Pricing peak reductions were multiplied by the $/kW-year estimated in the AESC 2021 Report for the System Capacity, Transmission and Distribution capacity reductions.

None of the above calculations required having a specific rate design or bill impacts identified, and none of the benefits calculated included any bill savings for customers.

PUC 7-8

Data Requests Regarding June 13, 2023 Technical Session

Request:

Are there meters on the market other than the chosen Revelo meter that can operate with the Wi-SUN network but that do not have distributed intelligence built in (described generally as the "edge card")?

a. If the answer is yes, does Landis+Gyr have other meters?

b. If the answer is yes, do other meter companies have them?

Response:

a. No, at this time Landis+Gyr does not offer a meter that is compatible with Wi-SUN and does not contain an edge card.

b. No, no other meter companies currently have a meter that is compatible with Wi-SUN and does not have distributed intelligence built in using an edge card.

PUC 7-9

Data Requests Regarding Supplemental Testimony

Revenue Requirement and Recovery

Request:

Referring to Schedule SAB BLJ-R, pages 2 through 10, please provide a similar set of schedules with the following additions and changes:

a. Instead of showing two 6-month rate reconciliation changes per year, restate the schedules in 12-month annual rate changes for the illustrative years of 2024, 2025, and 2026;

b. Add sub-lines under line (1) of column (a) which separately shows the revenue requirement from capital additions and the revenue requirement from O&M that are the components of line (1); and

c. Add sub-lines under line (7) which illustrate the amount of the fixed customer charge which are attributable to the referenced revenue requirements from the capital additions and separately, from the O&M expenses.

NOTE: This is designed to illustrate the split of revenue requirement between the two accounting categories until the time that new base rates go into effect from the projected next base distribution rate case.

Response:

Please see Attachment PUC 7-9 which reflects the changes and additions requested above.

For purposes of this response, the Company assumed the annual rate change was effective January 1 of each year, for the revenue requirement incurred through September of the prior year. Similar to Schedule SAB BLJ-R, the revenue requirement amounts used in the calculations on Attachment PUC 7-9 are derived from the original filing on Schedule SAB/BLJ-1. Please note that the O&M revenue requirement amounts on Attachment PUC 7-9 are net of the proposed O&M benefits. In addition to showing the Capital and O&M amounts separately, the Company has also included a line to reflect the levels of base rate recovery that the Company has proposed to reduce the AMF revenue requirement on Schedule SAB/BLJ-1.

The Narragansett Electric Company
Illustrative AMF Factor By Customer Charge
Summary

Line No.		Source	Residential A-16 / A60	Small C&I C-06	General C&I G-02	Large Demand B-32 / G-32	Propulsion X-01	Lighting S-05 / S-06 S-10 / S-14
			(b)	(c)	(d)	(e)	(f)	(g)
AMF Factor								
(1)	Illustrative AMF Factor per customer charge January 2024 - December 2024	Page 2	$0.041	$0.067	$0.614	$4.686	$42.840	$2.417
(2)	Illustrative AMF Factor per customer charge January 2025 - December 2025	Page 3	$0.250	$0.411	$3.753	$28.765	$261.603	$15.298
(3)	Illustrative AMF Factor per customer charge January 2026 - December 2026	Page 4	$1.285	$2.110	$19.271	$148.292	$1,341.589	$81.382
(4)	Illustrative AMF Factor per customer charge January 2027 - December 2027	Page 5	$2.296	$3.767	$34.425	$265.895	$2,393.427	$150.645

The Narragansett Electric Company
Illustrative AMF Factor by Customer Charge
For the Period January 1, 2024 through December 31, 2024

Line No.		Total	Residential A-16 / A60	Small C&I C-06	General C&I G-02	Large Demand B-32 / G-32	Propulsion X-01	Lighting S-05 / S-06 S-10 / S-14
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
(1)	AMF Revenue Requirement October 2022 through September 2023							
	a) Capital Revenue Requirement	$183,673						
	b) O&M Revenue Requirement (Net of benefits)	$534,688						
	c) Credits to Revenue Requirement for Base Rate Level	-$325,733						
	d) 'Total AMF Revenue Requirement October 2022 through September 2023	$392,628						
(2)	Percentage of Total	100.00%	55.6%	11.1%	15.4%	15.0%	0.1%	2.7%
(3)	Allocated AMF Revenue Requirement							
	a) Allocated Capital Revenue Requirement	$183,673	$102,187	$20,313	$28,274	$27,617	$241	$5,041
	b) Allocated O&M Revenue Requirement (Net of benefits)	$534,688	$297,476	$59,134	$82,307	$80,396	$701	$14,675
	c) Allocated Credits to Revenue Requirement for Base Rate Level	-$325,733	-$181,223	-$36,025	-$50,142	-$48,977	-$427	-$8,940
	c) Total Allocated AMF Revenue Requirement	$392,628	$218,440	$43,423	$60,439	$59,036	$514	$10,776
(4)	(Over)/Under Recovery for Prior Period	$0	$0	$0	$0	$0	$0	$0
(5)	Total Revenue Requirement and Reconciliation	$392,628	$218,440	$43,423	$60,439	$59,036	$514	$10,776
(6)	Forecasted Customer Count - January 2024 through December 2024	6,106,645	5,345,657	645,433	98,486	12,599	12	4,458
(7)	Illustrative AMF Factor per Customer Charge							
	a) Illustrative AMF Factor per Customer Charge - Capital related		$0.019	$0.031	$0.287	$2.192	$20.041	$1.131
	b) Illustrative AMF Factor per Customer Charge - O&M related		$0.056	$0.092	$0.836	$6.381	$58.340	$3.292
	c) Illustrative AMF Factor per Customer Charge - Credits related		($0.034)	($0.056)	($0.509)	($3.887)	($35.541)	($2.005)
	d) Total Illustrative AMF Factor per Customer Charge		$0.041	$0.067	$0.614	$4.686	$42.840	$2.417

Line Notes:

(1)(a)	Schedule SAB/BLJ-1, Page 1, Line 4, Column (a)
(1)(b)	Schedule SAB/BLJ-1, Page 1, Column (a) Line 9 minus Line 13
(1)(c)	Schedule SAB/BLJ-1, Page 1, Column (a) Line 16 + Lines 17 through 20
(1)(d)	Line 1a + 1b +1c
(2)	Schedule SAB/BLJ-2, Page 1, Line 3
(3)(a)	Line (1)(a) Column (a) x Line (2)
(3)(b)	Line (1)(b) Column (a) x Line (2)
(3)(c)	Line (1)(c) Column (a) x Line (2)
(3)(d)	Line 3a + 3b +3c
(4)	Calculated (over)/under recovery from difference in forecasted vs. actual customers for prior periods
(5)	Line (3) + Line (4)
(6)	Per Company Forecasts
(7)(a)	Line (3)(a) divided by Line (6)

The Narragansett Electric Company
Illustrative AMF Factor by Customer Charge
For the Period January 1, 2025 through December 31, 2025

Line No.		Total	Residential A-16 / A60	Small C&I C-06	General C&I G-02	Large Demand B-32 / G-32	Propulsion X-01	Lighting S-05 / S-06 S-10 / S-14
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
(1)	AMF Revenue Requirement October 2023 through September 2024							
	a) Capital Revenue Requirement	$2,709,655						
	b) O&M Revenue Requirement (Net of benefits)	$3,731,264						
	c) Credits to Revenue Requirement for Base Rate Level	-$4,033,026						
	d) 'Total AMF Revenue Requirement October 2023 through September 2024	$2,407,893						
(2)	Percentage of Total	100.00%	55.6%	11.1%	15.4%	15.0%	0.1%	2.7%
(3)	Allocated AMF Revenue Requirement							
	a) Allocated Capital Revenue Requirement	$2,709,655	$1,507,526	$299,676	$417,112	$407,424	$3,550	$74,367
	b) Allocated O&M Revenue Requirement (Net of benefits)	$3,731,264	$2,075,902	$412,661	$574,374	$561,034	$4,889	$102,405
	c) Allocated Credits to Revenue Requirement for Base Rate Level	-$4,033,026	-$2,243,788	-$446,035	-$620,826	-$606,407	-$5,284	-$110,687
	c) Total Allocated AMF Revenue Requirement	$2,407,893	$1,339,640	$266,302	$370,660	$362,051	$3,155	$66,085
(4)	(Over)/Under Recovery for Prior Period	$0	$0	$0	$0	$0	$0	$0
(5)	Total Revenue Requirement and Reconciliation	$2,407,893	$1,339,640	$266,302	$370,660	$362,051	$3,155	$66,085
(6)	Forecasted Customer Count - January 2025 through December 2025	6,120,547	5,357,165	647,691	98,773	12,586	12	4,320
(7)	Illustrative AMF Factor per Customer Charge							
	a) Illustrative AMF Factor per Customer Charge - Capital related		$0.281	$0.463	$4.223	$32.370	$294.388	$17.215
	b) Illustrative AMF Factor per Customer Charge - O&M related		$0.388	$0.637	$5.815	$44.575	$405.379	$23.706
	c) Illustrative AMF Factor per Customer Charge - Credits related		($0.419)	($0.689)	($6.285)	($48.180)	($438.164)	($25.623)
	d) Total Illustrative AMF Factor per Customer Charge		$0.250	$0.411	$3.753	$28.765	$261.603	$15.298

Line Notes:

(1)(a)	Schedule SAB/BLJ-1, Page 1, Line 4, Column (b)
(1)(b)	Schedule SAB/BLJ-1, Page 1, Column (b) Line 9 minus Line 13
(1)(c)	Schedule SAB/BLJ-1, Page 1, Column (b) Line 16 + Lines 17 through 20
(1)(d)	Line 1a + 1b +1c
(2)	Schedule SAB/BLJ-2, Page 1, Line 3
(3)(a)	Line (1)(a) Column (a) x Line (2)
(3)(b)	Line (1)(b) Column (a) x Line (2)
(3)(c)	Line (1)(c) Column (a) x Line (2)
(3)(d)	Line 3a + 3b +3c
(4)	Calculated (over)/under recovery from difference in forecasted vs. actual customers for prior periods
(5)	Line (3) + Line (4)
(6)	Per Company Forecasts
(7)(a)	Line (3)(a) divided by Line (6)

The Narragansett Electric Company
Illustrative AMF Factor by Customer Charge
For the Period January 1, 2026 through December 31, 2026

Line No.		Total	Residential A-16 / A60	Small C&I C-06	General C&I G-02	Large Demand B-32 / G-32	Propulsion X-01	Lighting S-05 / S-06 S-10 / S-14
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
(1)	AMF Revenue Requirement October 2024 through September 2025							
	a) Capital Revenue Requirement	$9,799,523						
	b) O&M Revenue Requirement (Net of benefits)	$5,686,855						
	c) Credits to Revenue Requirement for Base Rate Level	-$3,086,148						
	d) 'Total AMF Revenue Requirement October 2024 through September 2025	$12,400,230						
(2)	Percentage of Total	100.00%	55.6%	11.1%	15.4%	15.0%	0.1%	2.7%
(3)	Allocated AMF Revenue Requirement							
	a) Allocated Capital Revenue Requirement	$9,799,523	$5,451,999	$1,083,784	$1,508,494	$1,473,459	$12,839	$268,949
	b) Allocated O&M Revenue Requirement (Net of benefits)	$5,686,855	$3,163,901	$628,941	$875,408	$855,077	$7,451	$156,076
	c) Allocated Credits to Revenue Requirement for Base Rate Level	-$3,086,148	-$1,716,989	-$341,314	-$475,067	-$464,034	-$4,043	-$84,700
	c) Total Allocated AMF Revenue Requirement	$12,400,230	$6,898,911	$1,371,411	$1,908,834	$1,864,502	$16,246	$340,325
(4)	(Over)/Under Recovery for Prior Period	$0	$0	$0	$0	$0	$0	$0
(5)	Total Revenue Requirement and Reconciliation	$12,400,230	$6,898,911	$1,371,411	$1,908,834	$1,864,502	$16,246	$340,325
(6)	Forecasted Customer Count - January 2026 through December 2026	6,134,178	5,368,464	649,895	99,052	12,573	12	4,182
(7)	Illustrative AMF Factor per Customer Charge							
	a) Illustrative AMF Factor per Customer Charge - Capital related		$1.016	$1.668	$15.229	$117.191	$1,060.217	$64.313
	b) Illustrative AMF Factor per Customer Charge - O&M related		$0.589	$0.968	$8.838	$68.008	$615.265	$37.322
	c) Illustrative AMF Factor per Customer Charge - Credits related		($0.320)	($0.525)	($4.796)	($36.907)	($333.892)	($20.254)
	d) Total Illustrative AMF Factor per Customer Charge		$1.285	$2.110	$19.271	$148.292	$1,341.589	$81.382

Line Notes:

(1)(a)	Schedule SAB/BLJ-1, Page 1, Line 4, Column (c)
(1)(b)	Schedule SAB/BLJ-1, Page 1, Column (c) Line 9 minus Line 13
(1)(c)	Schedule SAB/BLJ-1, Page 1, Column (c) Line 16 + Lines 17 through 20
(1)(d)	Line 1a + 1b +1c
(2)	Schedule SAB/BLJ-2, Page 1, Line 3
(3)(a)	Line (1)(a) Column (a) x Line (2)
(3)(b)	Line (1)(b) Column (a) x Line (2)
(3)(c)	Line (1)(c) Column (a) x Line (2)
(3)(d)	Line 3a + 3b +3c
(4)	Calculated (over)/under recovery from difference in forecasted vs. actual customers for prior periods
(5)	Line (3) + Line (4)
(6)	Per Company Forecasts
(7)(a)	Line (3)(a) divided by Line (6)

The Narragansett Electric Company
Illustrative AMF Factor by Customer Charge
For the Period January 1, 2027 through December 31, 2027

Line No.		Total	Residential A-16 / A60	Small C&I C-06	General C&I G-02	Large Demand B-32 / G-32	Propulsion X-01	Lighting S-05 / S-06 S-10 / S-14
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
(1)	AMF Revenue Requirement October 2025 through September 2026							
	a) Capital Revenue Requirement	$19,962,090						
	b) O&M Revenue Requirement (Net of benefits)	$3,468,301						
	c) Credits to Revenue Requirement for Base Rate Level	-$1,234,459						
	d) 'Total AMF Revenue Requirement October 2025 through September 2026	$22,195,932						
(2)	Percentage of Total	100.00%	55.6%	11.1%	15.4%	15.0%	0.1%	2.7%
(3)	Allocated AMF Revenue Requirement							
	a) Allocated Capital Revenue Requirement	$19,962,090	$11,105,979	$2,207,719	$3,072,873	$3,001,505	$26,153	$547,861
	b) Allocated O&M Revenue Requirement (Net of benefits)	$3,468,301	$1,929,601	$383,579	$533,894	$521,495	$4,544	$95,188
	c) Allocated Credits to Revenue Requirement for Base Rate Level	-$1,234,459	-$686,796	-$136,526	-$190,027	-$185,614	-$1,617	-$33,880
	c) Total Allocated AMF Revenue Requirement	$22,195,932	$12,348,785	$2,454,772	$3,416,740	$3,337,386	$29,080	$609,169
(4)	(Over)/Under Recovery for Prior Period	$0	$0	$0	$0	$0	$0	$0
(5)	Total Revenue Requirement and Reconciliation	$22,195,932	$12,348,785	$2,454,772	$3,416,740	$3,337,386	$29,080	$609,169
(6)	Forecasted Customer Count - January 2027 through December 2027	6,144,905	5,377,476	651,570	99,251	12,552	12	4,044
(7)	Illustrative AMF Factor per Customer Charge							
	a) Illustrative AMF Factor per Customer Charge - Capital related		$2.065	$3.388	$30.960	$239.134	$2,152.548	$135.484
	b) Illustrative AMF Factor per Customer Charge - O&M related		$0.359	$0.589	$5.379	$41.548	$373.993	$23.540
	c) Illustrative AMF Factor per Customer Charge - Credits related		($0.128)	($0.210)	($1.915)	($14.788)	($133.114)	($8.378)
	d) Total Illustrative AMF Factor per Customer Charge		$2.296	$3.767	$34.425	$265.895	$2,393.427	$150.645

Line Notes:

(1)(a)	Schedule SAB/BLJ-1, Page 1, Line 4, Column (d)
(1)(b)	Schedule SAB/BLJ-1, Page 1, Column (d) Line 9 minus Line 13
(1)(c)	Schedule SAB/BLJ-1, Page 1, Column (d) Line 16 + Lines 17 through 20
(1)(d)	Line 1a + 1b +1c
(2)	Schedule SAB/BLJ-2, Page 1, Line 3
(3)(a)	Line (1)(a) Column (a) x Line (2)
(3)(b)	Line (1)(b) Column (a) x Line (2)
(3)(c)	Line (1)(c) Column (a) x Line (2)
(3)(d)	Line 3a + 3b +3c
(4)	Calculated (over)/under recovery from difference in forecasted vs. actual customers for prior periods
(5)	Line (3) + Line (4)
(6)	Per Company Forecasts
(7)(a)	Line (3)(a) divided by Line (6)

PUC 7-11

Data Requests Regarding Supplemental Testimony

Revenue Requirement and Recovery

Request:

PUC 4-2(b) requested "some common examples of investments in the past where the Company considered capex investments to be placed in service, and therefore, eligible for rate base, when the investment was 'ready for its intended use' but was not yet being used for service to customers.'" It does not appear the Company provided a response to this portion of the question. Please respond to the quoted request.

Response:

The Company does not place capital investments into service or make investments eligible for rate base until they are being used for service to customers, also known as being "used and useful." As indicated in the response to PUC 4-2(b), the Company considers the term "ready for its intended use" to also have the same meaning as "used and useful." As such, for utility plant that would serve an operational function as identified in PUC 4-2, the Company would not place capital investments into service if they were not yet being used for service to customers.

This has been the Company's position historically and the Company plans to use this same standard for future capital investments. Therefore, there are no examples from the past where the Company has placed capital investments in service and in rate base when it was not yet being used for service to customers.

PUC 7-12

Data Requests Regarding Supplemental Testimony

Revenue Requirement and Recovery

Request:

PUC 4-2(a) references the "Company." The Narragansett Electric Company has been operating as a National Grid company and now as a PPL company. Please clarify how the respondents are using the term "Company" in this response.

Response:

In the response to PUC 4-2(a), the term "Company" is meant to be The Narragansett Electric Company. The standard to capitalize investments into service once it is determined to be used and useful is the same process for The Narragansett Electric Company under both its previous operation as a National Grid company and under its current operation as a PPL company.

PUC 7-13

Data Requests Regarding Supplemental Testimony

Revenue Requirement and Recovery

Request:

Please identify **all** annual deferrals of revenue recovered in base distribution rates which arose out of rate allowances in the Multi-Year Rate Plan in Docket No. 4770 and are being held or will be held for crediting to customers. For example, there is a deferral which was identified in response to PUC 1-27 in this docket relating to preparation of the AMF business case and there were deferrals that arise out of underspending of Power Sector Transformation programs, some of which were identified in Docket No. 4770A (filed on November 3, 2021). There also are credits referenced in Schedule SAB/BLJ-1 in Book 3 of the original AMF filing in this docket Please show the annual amounts by rate year and projections of future annual amounts through the Company's forecasted date when new base distribution rates would take effect from the Company's next base distribution rate case and include the expected cumulative amounts for each deferral.

Response:

Please see Attachment PUC 7-13 for the forecasted deferral balances of all annual deferrals of revenue recovered in base distribution rates that arose out of rate allowances in Docket No. 4770 and that are currently in a liability position, or the Company forecasts will be in a liability position at the time of the next distribution rate case for crediting to customers. The attachment includes the deferral by rate year as well as a cumulative total in Column Z. For purposes of this response, the Company assumed new distribution base rates would take effect September 1, 2026; as such the deferral balances were forecasted through August 31, 2026.

In addition to the programs listed on Attachment PUC 7-13, Docket No. 4770 established rate allowances for other Grid Mod costs in Rate Years 2 and 3 (Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 25). Per the Amended Settlement Agreement, there are no deferrals associated with these programs if the Company's actual costs are more or less than the rate allowance for these programs. However, assuming recovery of the AMF revenue requirement begins prior to the next base distribution rate case, the Company has proposed on Schedule SAB/BLJ-1, Lines 16, 18 and 19, to reduce the AMF annual revenue requirements with the AMF related portion of the Grid Mod annual rate allowances collected in base distribution rates. For illustrative purposes, Schedule SAB/BLJ-1 reflects the reduction to the AMF revenue requirements for the amount in base rate allowances for all 20 years; however, once new base distribution rates would be effective, this adjustment to the AMF revenue requirement would not be necessary.

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

Line No.		Rate Year Ending August 31, 2019			Rate Year Ending August 31, 2020			Rate Year Ending August 31, 2021			Rate Year Ending August 31, 2022			Rate Year Ending August 31, 2023		
		Actual Spend	**Rate Allowance**	**Deferral**	**Actual Spend**	**Rate Allowance**	**Deferral**	**Actual Spend**	**Rate Allowance**	**Deferral**	**Actual Spend**	**Rate Allowance**	**Deferral**	**Actual Spend ***	**Rate Allowance**	**Deferral**
		(a)	(b)	(c)=(a)-(b)	(d)	(e)	(f)=(d)-(e)	(g)	(h)	(i)=(g)-(h)	(j)	(k)	(l)=(j)-(k)	(m)	(n)	(o)=(m)-(n)
1	AMI Business Case Study	$2,000,000	$666,667	$1,333,333	$0	$666,667	($666,667)	$0	$666,667	($666,667)	$0	$666,667	($666,667)	$0	$666,667	($666,667)
2	GIS Enhancements (IS)	$11,119	$142,333	($131,214)	$20,451	$142,333	($121,883)	$8,739	$142,333	($133,595)	$115,356	$142,333	($26,978)	$0	$142,333	($142,333)
3	Special Sector: Storage	$0	$112,586	($112,586)	$5,464	$259,668	($254,204)	$5,564	$411,986	($406,422)	$0	$411,986	($411,986)	$0	$411,986	($411,986)
4	Special Sector: Electric Transportation **	$312,370	$681,300	($368,930)	$1,106,790	$1,151,751	($44,961)	$1,023,537	$2,151,776	($1,128,239)	$1,419,934	$2,151,776	($731,842)	$1,238,109	$2,151,776	($913,667)
				$0			$0			$0			$0			$0
	Total	**$2,323,489**	**$1,602,886**	**$720,603**	**$1,132,705**	**$2,220,419**	**($1,087,714)**	**$1,037,839**	**$3,372,762**	**($2,334,923)**	**$1,535,290**	**$3,372,762**	**($1,837,472)**	**$1,238,109**	**$3,372,762**	**($2,134,653)**

* Actual Spend through May 2023 - forecasted June 2023 through August 2023

** The deferral related to the Electric Transportation Initiatives (ETI) is being considered for use to fund additional ETI programs until the next rate case (subject to PUC review and approval). The Company may make a filing in the Fall of 2023 for its proposal on use of the deferral.

Line Notes:
1b, 1e, 1h Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 26
2b, 2e, 2h Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 27
3b, 3e, 3h Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 36
4b, 4e, 4h Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 33

Columns n, p, s, v - Rate Allowance from Rate Year August 2021 continued until next base distribution rate case

Columns a, d, g, j, m - revenue requirement on actual spend
Columns o, r, u - revenue requirement on forecasted spend

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

Line No.		Rate Year Ending August 31, 2024			Rate Year Ending August 31, 2025			Rate Year Ending August 31, 2026			Cumulative Deferral Through August 31, 2026		
		Forecasted Actual Spend	Rate Allowance	Deferral	Forecasted Actual Spend	Rate Allowance	Deferral	Forecasted Actual Spend	Rate Allowance	Deferral	Forecasted Actual Spend	Rate Allowance	Deferral
		(o)	(p)	(q)=(o)-(p)	(r)	(s)	(t)=(r)-(s)	(u)	(v)	(w)=(u)-(v)	(x)	(y)	(z)=(x)-(y)
1	AMI Business Case Study	$0	$666,667	($666,667)	$0	$666,667	($666,667)	$0	$666,667	($666,667)	$2,000,000	$5,333,333	($3,333,333)
2	GIS Enhancements (IS)	$0	$142,333	($142,333)	$0	$142,333	($142,333)	$0	$142,333	($142,333)	$155,664	$1,138,667	($983,002)
3	Special Sector: Storage	$0	$411,986	($411,986)	$0	$411,986	($411,986)	$0	$411,986	($411,986)	$11,028	$2,844,170	($2,833,142)
4	Special Sector: Electric Transportation **	$765,000	$2,151,776	($1,386,776)	$648,000	$2,151,776	($1,503,776)	$570,000	$2,151,776	($1,581,776)	$7,083,740	$14,743,707	($7,659,967)
				$0			$0			$0	$0	$0	$0
	Total	**$765,000**	**$3,372,762**	**($2,607,762)**	**$648,000**	**$3,372,762**	**($2,724,762)**	**$570,000**	**$3,372,762**	**($2,802,762)**	**$9,250,432**	**$24,059,877**	**($14,809,445)**

* Actual Spend through May 2023 - forecasted June 2023 through August 2023

** The deferral related to the Electric Transportation Initiatives (ETI) is being considered for use to fund additional ETI programs until the next rate case (subject to PUC review and approval). The Company may make a filing in the Fall of 2023 for its proposal on use of the deferral.

Line Notes:
1b, 1e, 1h Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 26
2b, 2e, 2h Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 27
3b, 3e, 3h Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 36
4b, 4e, 4h Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 33

Columns n, p, s, v - Rate Allowance from Rate Year August 2021 continued until next base distribution rate case

Columns a, d, g, j, m - revenue requirement on actual spend
Columns o, r, u - revenue requirement on forecasted spend

PUC 7-15

Data Requests Regarding Supplemental Testimony

MDMS Allocation

Request:

Referring to the response to PUC 2-25(d), when estimating that it would cost $5.66 million to implement only a non-AMF MDMS compared to MDMS which included AMF functionality, it appears that the Company applied the allocation percentage of 56% to the total MDMS implementation cost to arrive at the $5.66 million.

a. Please explain whether and the extent to which the Company believes it is reasonable to assume that the actual cost of implementing a non-AMF MDMS aligns with an allocation base upon the number of functionalities.

b. Why did PPL not request a separate price estimate from Landis+Gyr for the implementation of an MDMS that did not have any AMF functionalities to address the potential that there might be a decision not to proceed with AMF?

Response:

For the purposes of this response PPL is assuming the referenced response was intended to be PUC 3-25(d) rather than PUC 2-25(d). PPL would like to clarify that the $5.66 million to implement a non-AMF MDMS was an estimate only and was not meant to imply a total implementation cost as part of a standalone implementation.

a. When estimating costs for a system implementation, it is a common practice to base an estimate, which determines level of work, on the number of functionality requirements for that system. The Company performed this as described in the Methodology and Basis of Estimation for Systems Costs within the AMF Benefit Cost Memorandum in Attachment H to the AMF Business Case.

Please see Confidential Attachment PUC 3-22-1 and response to PUC 7-16 describing the line items. As noted in the AMF Benefit Cost Memorandum, for the estimated MDMS Implementation costs, AMF and TSA Exit were based on the 224 requirements as described in PUC 7-14 while the estimated MDMS Ongoing Software as a Service ("SaaS") costs were based on functionalities and endpoint population. The 44% AMF and 56 % Non-AMF split was based on allocation of the total number of MDMS functionality requirements (224). Upon review of all functionality requirements for MDMS implementation, 44%, or 99 of the 224, were determined to be specific to AMF. See PUC 7-14 and Confidential Attachment PUC 3-22-2. As described in the Company's response to PUC 3-25, the Company has taken diligent steps to allocate appropriately the costs between those necessary only for AMF, and those that will be necessary even in the absence of AMF. The Company considers its methodology reasonable and appropriate to estimate MDMS AMF and TSA Exit costs.

b. PPL did not request a separate price estimate from Landis+Gyr for the implementation of an MDMS that did not have any AMF functionalities because the associated TSA-Exit and AMF timelines materially overlap, resulting in the need to implement both sets of functionality requirements at the same time. If both sets were not introduced at the same time, then waiting to introduce the AMF requirements until after a potential AMF approval decision would then either require revisiting key MDMS functionality and adding risk to successfully exiting TSA or it would mean proceeding with the non-AMF functionality and delaying the AMF functionality from the proposed timeline. To address the potential that there might be a decision not to proceed with AMF, PPL included in the implementation Statement of Work with Landis+Gyr (Attachment PUC 6-3-4), the right to terminate or modify the implementation once that outcome is known. If AMF was not approved or was altered, updating the contract would likely happen, and: 1) AMF activities that have already occurred would be sunk cost by PPL/RIE, 2) AMF activities that have not started would be stopped and removed from the Statement of Work, and 3) TSA Exit work and activities would continue. This was the intent and purpose of clearly allocating requirements and cost b/w TSA Exit and AMF.

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

Redacted
PUC 7-16

Data Requests Regarding Supplemental Testimony

MDMS Allocation

Request:

Referring to Confidential Attachment PUC 3-22-1, please provide a more specific explanation and identify the sources and derivation of each of the numbers in the following cells: Columns F through L, lines 6, 7, 9, and 10.

Response:

Confidential Attachment PUC 3-22-1, Line 6, Columns F through L: Using costs from the Rhode Island Energy BCA Model (Confidential Attachment PUC 3-2-1) ("RIE BCA"), Software as a Service (SaaS) Vendor - MDMS (Implement) equaling $[redacted] (from RIE BCA, tab 10, Column O Line 84) and SI Vendor (TCS) - MDMS (Implement) equaling $[redacted] (from RIE BCA, tab 10, Column O, line 85) (taken from TCS estimate of work requirements). Total Nominal Dollars (capital) for these 2 lines in Column F. Columns I through L show the costs for each of the years 2022-2024. The source can be found in the RIE BCA; the sum of the values found in tab:10-RI AMF Cost Model cells R84 + R85 (year 1), S84+S85 (year 2), T84+T85 (year 3), U84+U85 (year 4). All occur within the first 4 years so the total is shown in Column G and zero in Column H.

Confidential Attachment PUC 3-22-1, Line 7, Columns F through L: Using costs from the RIE BCA Model (Confidential Attachment PUC 3-2-1), Annual License (SaaS) – MDMS equaling $[redacted] (from RIE BCA, tab 10, Column O, Line 86). Total nominal dollars (OpEx) in Column F. The BCA estimated $[redacted] per year for SaaS annual fees and escalated per Core CPI in future years. Columns I through L show the costs estimated for each of the years 2022-2024. Costs begin in 2024 and continue through year 20. The source can be found in the RIE BCA; the sum of the values found in tab:10-RI AMF Cost Model cells R86 (year 1), S86 (year 2), T86 (year 3), U86 (year 4). The total in Column G represents the years 1-4 costs and Column H represents the years 5-20 costs.

Line 9, Columns F through L: Using the estimated AMF costs of 44 percent of total MDMS Implementation costs and 56 percent are non-AMF Implementation costs, all line items in line 6 were divided by the 44 percent and then multiplied by the 56 percent to arrive at the Estimated Non-AMF MDMS Implementation costs (Years 1-4). The 44 percent/56 percent split was based on total number of PPL requirements (224). Upon review of all requirements for MDMS implementation, 44 percent, or 99 of the 224, were determined to be related to AMF. See PUC 7-14 and PUC 3-22 and Confidential Attachment PUC 3-22-2.

Line 10, Columns F through L: Estimating that Total Ongoing SaaS costs applied 52 percent to AMF and 48 percent to non-AMF, all line items in line 7 were divided by the 52 percent and then multiplied by the 48 percent to arrive at the Estimated Non-AMF MDMS Ongoing SaaS costs. The 52 percent/48 percent split for Ongoing SaaS costs was based on functionalities and endpoint population as described in the AMF Benefit Cost Memo – Attachment H (Confidential) stating the breakdown as follows: AMR – 28 percent for gas (non-AMF), Retail Settlement – 20 percent (non-AMF), and Electric AMF – 52 percent (AMF). Please see the Company's response to data request PUC 3-22.

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

PUC 7-17

Data Requests Regarding Supplemental Testimony

MDMS Allocation

Request:

Referring to the Attachment B excel spreadsheet referenced in the Supplemental Testimony, please provide a more specific explanation and identify the sources and derivation of each of the numbers in the following cells: Column E, lines 4, 8, 9, 18, 19, 20, 24, 25, and 26.

Response:

For Tab "MDM BCA vs. L+G Svc Order 2" in Attachment B, the following describe these line items:

- Row 4: represents the Rhode Island Energy AMF Advanced Metering Functionality ("AMF") Benefit-Cost Analysis ("BCA") total MDMS SaaS annual amounts; source is the Rhode Island Energy AMF BCA Model.
- Row 8: represents the AMF Landis+Gyr Service Order #2 calculations using the contractual calculations and deployment schedule. The components that make up the value are found in E18, E19, and E20. Each of these three components derivations can be found on Landis+Gyr Service Order #2 (MDM) across H21-O21; H29-O29; and 50 percent of H66-O66. This calculation assumes a 2 percent escalation per year.
- Row 9: represents the AMR Landis+Gyr Service Order #2 calculations using contract costs for 20 years if AMR meters stayed in service entire time. The components that make up the value are found in E24, E25, and E26. Each of these three components derivations can be found on Landis+Gyr Service Order #2 (MDM) across H49-O49; H57-O57; and 50% of H66-O66. This calculation assumes a 2 percent escalation per year.
- Row 18: represents the AMF component – Production as calculated per the Landis+Gyr Service Order #2, table titled SaaS MDMS AMI Pricing (Electric Endpoints) – for Production. Derivations can be found on Landis+Gyr Service Order #2 (MDM) across H21-O21. This calculation assumes a 2 percent escalation per year.
- Row 19: represents the AMF component – Disaster Recovery as calculated per the Landis+Gyr Service Order #2, table titled SaaS MDMS AMI Meter Pricing (Electric Endpoints) – for Disaster Recovery. Derivations can be found on Landis+Gyr Service Order #2 (MDM) across H29-O29. This calculation assumes a 2 percent escalation per year.

- Row 20: represents the SaaS Gridstream MDMS Lower Environment (each) per Landis+Gyr Service Order#2. This includes two environments – Development and Testing. Derivations can be found on Landis+Gyr Service Order #2 (MDM) across H66-O66. This calculation assumes a 2 percent escalation per year. The Company attributes 50 percent of this line item to AMF.
- Row 24: represents the AMR component – Production per the AMR Landis+Gyr Service Order #2 calculations, table titled SaaS MDMS AMR Pricing (Electric Endpoints) – for Production using contract costs for 20 years if AMR meters stayed in service entire time. Derivations can be found on Landis+Gyr Service Order #2 (MDM) across H49-O49. This calculation assumes a 2 percent escalation per year.
- Row 25: represents the AMR component – Disaster Recovery per the AMR Landis+Gyr Service Order #2 calculations, table titled SaaS MDMS AMR Pricing (Electric Endpoints)- Disaster Recovery using contract costs for 20 years if AMR meters stayed in service entire time. Derivations can be found on Landis+Gyr Service Order #2 (MDM) across H57-O57. This calculation assumes a 2 percent escalation per year.
- Row 26: represents the SaaS Gridstream MDMS Lower Environment (each) per Landis+Gyr Service Order #2. This includes two environments – Development and Testing. Derivations can be found on Landis+Gyr Service Order #2 (MDM) across H66-O66. This calculation assumes a 2 percent escalation per year. The Company attributes 50 percent of this line item to AMR.

PUC 7-18

Data Requests Regarding Supplemental Testimony

Landis+Gyr Service Order #2 Charges

Request:

Referring to Service Order #2 from the Landis+Gyr SaaS Agreement (Supplemental Attachment R 1-3, pages 51-55), please provide an explanation of how the Landis+Gyr pricing was developed and negotiated to identify separate charges relating to MDMS AMR pricing and MDMS AMI pricing.

Response:

The overall SaaS pricing was developed and negotiated through multiple steps. PPL Services Corporation ("PPL Services"), on behalf of Rhode Island Energy, provided Landis+Gyr with the needed functionality requirements and capabilities being sought for the Rhode Island electric service territory. Multiple meetings occurred to validate and finalize the requirements and capabilities. Additional meetings took place in which Landis+Gyr provided initial cost estimates, which were then iterated and negotiated on. PPL Services used PPL Electric Utilities' actual on-premises costs to benchmark and negotiate final pricing. This process was discussed further in the Supplemental testimony.

In the Advanced Metering Functionality ("AMF") Business Case Benefit-Cost Analysis ("BCA"), PPL Services used the percentage functionality requirements allocation between AMR/TSA Exit and AMF to estimate costs.

The contract Service Order #2 end point pricing specific to AMR and AMI, respectively, was determined by Landis+Gyr. This was based on the consideration of the ongoing cost for AMR in the event that AMF is not approved. Rhode Island Energy validated the reasonableness of the end-point pricing between AMR and AMI.

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

PUC 7-19

Data Requests Regarding Supplemental Testimony

Landis+Gyr Milestone Payments

Request:

Referring to the Payment Milestones in Section 5 of the Landis+Gyr Statement of Work, Supplemental Attachment R-1-4, pages 39-41, please explain the rationale and the basis for the allocation of milestone payments between "TSA Exit Payments" and "AMF Payments."

Response:

For the referenced statement of work, functionality requirements were created and then reviewed by Company personnel to determine the percentage of the requirements that support TSA Exit functionality (e.g. AMR Billing and retail settlement) and AMF capabilities. While most of the statement of work's requirements were directly in support of AMF and assigned as such, the MDMS is the area where capabilities are shared. The Company determined that 56 percent of the MDMS requirements were supporting TSA Exit requirements and 44 percent were supporting AMF requirements, and these percentages were then applied to the MDMS vendor implementation costs. Please see the Company's response to PUC 7-14 for additional details explaining these allocations.

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

PUC 7-20

Data Requests Regarding Supplemental Testimony

Landis+Gyr Milestone Payments

Request:

Please describe how the Company is accounting for the payment milestones relating to AMF payments to Landis+Gyr, as set forth in Section 5 of the Statement of Work. Is the Company commencing the accumulation of AFUDC when each of the payments are made to Landis+Gyr?

Response:

AMF payments relating to the Payment Milestones are accounted for as capital in the separate cost accumulation accounts set up for the AMF project. As of 6/21/23, the first two milestones have been paid to Landis+Gyr. These amounts were both charged to a capital account for the AMF project and were reclassified to account 183 Preliminary Survey and Investigation until approval is received. This account is not eligible for AFUDC.

Redacted
PUC 7-21

Data Requests Regarding Supplemental Testimony

Tata Consultancy Services Agreement

Request:

Referring to the Tata Consultancy Services agreement, Statement of Work (Attachment PUC 6-3-2), and the Milestone Pricing table shown on page 5 of 6,

a. Please provide a status update regarding the achievement of the milestones, indicating whether and when they were met, and whether payments have been made,

b. Please indicate whether the Company is or will be seeking recovery of any of these costs and, if so, whether they were booked as capital or O&M, and in what years recovery occurs,

c. Please indicate whether these are being treated as TSA Exit costs and/or AMF and, if so, show the breakdown of these categories, and explain how they were allocated between the two.

Response:

a. The four milestones listed were all achieved and paid to TCS totaling $[redacted].

Invoice #	Approval Date	Payment Date	Amount
USCI223011084	6/14/22	7/12/22	[redacted]
WBFI423005932A	6/14/22	7/12/22	[redacted]
USNI223021672	6/14/22	7/12/22	[redacted]
USNI223021673	6/14/22	7/12/22	[redacted]
USCI223022130	6/14/22	7/19/22	[redacted]
USCI223022131	6/14/22	7/19/22	[redacted]

b. The Company is not seeking recovery for these costs.

c. These costs were all TSA Exit costs. None were booked to AMF.

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

Redacted
PUC 7-22

Data Requests Regarding Supplemental Testimony

Tata Consultancy Services Agreement

Request:

Referring to the Tata Consultancy Services agreement, Statement of Work (Attachment PUC 6-3-3), and the Milestone Pricing table shown on pages 6-8,

a. Please provide a status update regarding the achievement of the milestones, indicating whether and when they were met, and whether payments have been made,

b. Please indicate whether the Company is or will be seeking recovery of any of these costs and, if so, whether they were booked as capital or O&M, and in what years recovery occurs,

c. Please indicate whether these are being treated as TSA Exit costs and/or AMF and, if so, show the breakdown of these categories, and explain how they were allocated between the two.

Response:

a. The three milestones listed were all achieved and paid to TCS totaling [redacted].

Invoice #	Approval Date	Payment Date	Amount
USCI223036707	8/13/22	12/8/22	[redacted]
USCI223050586	8/24/22	9/27/22	[redacted]
USCI223063717	11/28/22	11/29/22	[redacted]

b. The Company is not seeking recovery for these costs.
c. All of these costs were TSA exit costs. None were booked to AMF.

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

PUC 7-23

Data Requests Regarding Supplemental Testimony

Tata Consultancy Services Agreement

Request:

Referring to the Tata Consultancy Services agreement, Statement of Work (Attachment PUC 6-3-4), and the Milestone and Pricing tables shown at pages 19-22,

a. Please provide a status update regarding the achievement of the milestones, indicating whether and when they were met, and whether payments have been made,

b. Please indicate whether the Company is or will be seeking recovery of any of these costs and, if so, whether they were booked as capital or O&M, and in what years recovery occurs,

c. Please explain the basis for the allocations of these costs for each line shown in the pricing table which allocates between TSA-Exit and AMF.

Response:

a. As of 6/21/23, the first four milestones have been achieved. The first three were paid to TCS and the fourth one will be paid in June 2023. The total of these first 4 milestones is $4,075,000. The remaining 17 milestones have not been achieved as of 6/21/23.

Invoice #	Approval Date	Payment Date	Amount
USCI223081310	11/28/22	12/8/22	500,000
USCI223087034	11/28/22	12/20/22	625,000
USCI223122985	2/7/23	4/3/23	1,475,000
USCI224011124	5/15/23	Not paid yet	1,475,000

b. The Company will only be seeking recovery for the scope of work specific to AMF. As noted in the pricing section of the contract, each milestone is either all TSA-exit, all AMF or an allocation of both. The first four milestones that were paid all related to TSA-exit and were booked to the following account types.

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Invoice #	Amount	Capital accounts	O&M accounts
USCI223081310	500,000	150,000	350,000
USCI223087034	625,000	625,000	0
USCI223122985	1,475,000	1,475,000	0
USCI224011124	1,475,000	1,475,000	0

c. The Company worked in conjunction with the vendor to breakdown the costs between TSA Exit and AMF based on the estimated work. Using the planned scope for each of the milestones and the analysis of the requirements to determine the split between TSA Exit and AMF costs for the overall project, each milestone was assigned its value based upon the relative effort of each milestone.

In the course of reviewing the Tata Consultancy Services Agreement Statement of Work (Attachment PUC 6-3-4) in connection with preparing these responses, the Company identified certain discrepancies in how the allocations between TSA Exit and AMF were reflected in the agreement. The Company is in the process of working on an amendment to correct these discrepancies and will provide this amendment to the Commission when executed. The Company will also supplement this response on or before July 7, 2023, to provide the basis for the allocations of costs for each line shown in the pricing table.

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

PUC 7-24

Data Requests Regarding Supplemental Testimony

Tata Consultancy Services Agreement

Request:

In the response to PUC 3-21, the Company represented that the MDMS was "the only solution that has a direct overlap" between TSA Exit and AMF. It also states that "the other applications are either all TSA Exit or AMF." Please reconcile the representations in PUC 3-21 with the allocation of milestone payments in the Statement of Work, Attachment 6-3-4, pages 21-26.

Response:

PUC 3-21 pertains to Landis+Gyr. Landis+Gyr provides the MDMS solution.

Statement of Work, Attachment 6-3-4, pages 21-26, pertains to Tata Consultancy Services Limited ("TCS") and its milestones. TCS is neither an application nor a software solution. TCS is a company that provides integration services, and it has been awarded work as it relates to TSA Exit and AMF. The TCS milestone chart that is referenced breaks out those costs, and only the costs for the AMF milestones have been used in the AMF Business Case Benefit-Cost Analysis ("BCA"). This can be evidenced by inspection of cells D59, D66, D68, D76, D81, and D85 of tab 3-Cost Model Inputs and Calculations in the confidential AMF BCA Model - Attachment H - FINAL (Confidential).xlsx file.

For this reason, the Company's statement in response to PUC 3-21 is consistent with Attachment 6-3-4. The only solution that has a direct overlap is the MDMS solution because the Landis+Gyr MDMS software will process both the existing meters and the proposed AMF meters. TCS's scope of work is to integrate solution services, and it is not a solution or application.

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

PUC 7-25

Data Requests Regarding Supplemental Testimony

Copies of All Agreements

Request:

Please provide copies of all agreements with vendors for services or the implementation of capital projects relating to AMF in Rhode Island. This is an on-going obligation which response should be continuously updated during the course of these proceedings, as the Company or PPL Service Company executes new agreements.

Response:

Copies of the current agreements related to AMF have been provided. Confidential Attachment 7-25, is the first amendment to the Tata Consulting Implementation Services agreement. This amendment corrects a clerical error in the totals-only row for TSA Exit and AMF, respectively.

As noted in response to PUC 7-23, in the course of reviewing the Tata Consultancy Services Agreement Statement of Work (Attachment PUC 6-3-4) in connection with preparing these responses, the Company identified certain discrepancies in how the allocations between TSA Exit and AMF were reflected in the agreement. The Company is in the process of working on an additional amendment to correct these discrepancies and will provide this amendment to the Commission on or before July 7, 2023.

PPL and Rhode Island Energy are currently negotiating the following agreements and will provide copies when complete:

- Hardware equipment and network installation services with Landis+Gyr,
- Meter installation services with vendor to be determined,
- Project management office services with vendor to be determined.

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

Redacted

(Version 2.0)

First Amendment
to
Statement of Work, Contract No. 157776

This First Amendment to Statement of Work Contract Number 157776 (the "First Amendment") between Tata Consultancy Services ("Service Provider") and PPL Services Corporation ("Company") is made and entered into effective as of June 20, 2023. Service Provider and Company may be referred to individually as a "Party," and collectively as the "Parties."

Recitals

WHEREAS, Company and Service Provider entered into a Statement of Work (Contract Number 157776) dated September 1, 2022 ("Agreement"); and

WHEREAS, the Parties desire to amend the Agreement as more particularly set forth herein.

NOW THEREFORE, in consideration for the promises set forth herein, and intending to be legally bound, the Parties hereby agree as follows:

1. Terms and Conditions. Capitalized terms used but not defined herein shall have the respective meanings given such terms in the Agreement. In the event of a conflict between the terms and conditions of the Agreement and this First Amendment, the terms and conditions of this First Amendment shall prevail and control. The First Amendment constitutes the entire agreement and understanding of the Parties with respect to this subject matter and supersedes all oral communication and prior writings with respect thereto. The remaining terms of this Agreement are unchanged and are incorporated into this First Amendment by reference, as if set forth fully at length herein.

2. Due to an error in the final calculations of the "Allocation for TSA-Exit" and "Allocation for RIE AMF" columns, the Table of pricing in Section 7 (Pricing) of the Agreement shall be deleted in its entirety and replaced with the following:

Item	Allocation for TSA-Exit	Allocation for RIE AMF	Price [per unit/[OTHER]]	[Cost Structure]
1. Mobilization and 4 vendor SOWs	[redacted]	[redacted]	[redacted]	Fixed Fee
2. Completion of PI1 and 2 additional vendor SOWs	[redacted]	[redacted]	[redacted]	Fixed Fee
3. Completion of PI2	[redacted]	[redacted]	[redacted]	Fixed Fee
4. Completion of PI3	[redacted]	[redacted]	[redacted]	Fixed Fee
5. Completion of PI4, Ready for System Integrated Test	[redacted]	[redacted]	[redacted]	Fixed Fee
6. Completion of PI5 and System Integrated Test	[redacted]	[redacted]	[redacted]	Fixed Fee

Redacted

Item	Allocation for TSA-Exit	Allocation for RIE AMF	Price [per unit/[OTHER]]	[Cost Structure]
7. Ready for Network Deployment (Release 0)	[redacted]	[redacted]	[redacted]	Fixed Fee
8. **Release 1 TSA Exit Deployment**	[redacted]	[redacted]	[redacted]	Fixed Fee*
9. Completion of PI6	[redacted]	[redacted]	[redacted]	Fixed Fee
10. Completion of PI7	[redacted]	[redacted]	[redacted]	Fixed Fee
11. Release 2 – Ready for AMF Meter Deployment	[redacted]	[redacted]	[redacted]	Fixed Fee
12. Completion of PI8		[redacted]	[redacted]	Fixed Fee
13. Completion of PI9		[redacted]	[redacted]	Fixed Fee
14. Release 3 Deployment		[redacted]	[redacted]	Fixed Fee
15. Completion of PI10		[redacted]	[redacted]	Fixed Fee
16. Completion of PI11		[redacted]	[redacted]	Fixed Fee
17. Release 4 Deployment		[redacted]	[redacted]	Fixed Fee
18. Completion of PI12		[redacted]	[redacted]	Fixed Fee
19. Completion of PI13		[redacted]	[redacted]	Fixed Fee
20. Release 5 Deployment		[redacted]	[redacted]	Fixed Fee
21. Program Acceptance, Transition to Long-term care		[redacted]	[redacted]	Fixed Fee
	[redacted]	[redacted]	[redacted]	

* Training and data migration expenses for Release 1 are driven by the production data conversion activities and expected to be [redacted].

3. Miscellaneous

a. Entire Agreement. This First Amendment constitutes the entire agreement and understanding of the parties with respect to its subject matter and supercedes all oral communication and prior writings with respect thereto. The remaining terms of the Agreement are unchanged.

b. Amendments. No amendment, modification or waiver in respect to this First Amendment will be effective unless in writing (including a writing evidenced by a facsimile transmission) and executed by each of the parties.

a. Counterparts and Electronic Signatures. This First Amendment may be executed in one or more counterparts, with the same effect as if the Parties had signed the same document. Each counterpart so executed shall be deemed to be an original, and all such counterparts shall be construed together and shall constitute one agreement. Each Party agrees that the electronic signatures of the Parties included in this First Amendment are intended to and do hereby authenticate this writing and have the same force and effect as manual signatures. An electronic signature means any electronic sound, symbol, or process attached to or logically associated with a record and executed and adopted by a party with the intent to sign such record pursuant to the Pennsylvania Uniform Electronic Transactions Act (73 Pa. Stat. Ann. § 2260.101 et seq.), as amended from time to time. Each Party agrees that it will not challenge the enforceability of this First Amendment on the basis that it was signed electronically and further agrees that the electronic means of signing this First Amendment is commercially reasonable.

c. Headings. The heading used in this First Amendment are for convenience of reference only and are not to affect the construction of or to be taken into consideration in interpreting this Amendment.

d. Governing Law. This First Amendment will be governed by and construed in accordance with the laws of the Commonwealth of Pennsylvania without regard to conflict of laws principles.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF, the Parties, by their respective authorized representatives, have executed this First Amendment effective as of the date first written above.

Tata Consultancy Services	**PPL Services Corporation**
By: DocuSigned by: Sabyasachi Chandra CF9BAB7B2ECA4E7...	By: DocuSigned by: Darin Larrabee 5309A1BB247C437...
Name: Sabyasachi Chandra	Name: Darin Larrabee
Title: Business Unit Head - Utilities Americas	Title: Senior Category Manager
Date: 6/27/2023 | 9:55 AM EDT	Date: 6/20/2023 | 2:08 PM EDT