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Rhode Island Energy™
a PPL company

April 6, 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 Division Data Requests – Division Set 4

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 Division of Public Utilities & Carriers' (the "Division") Fourth Set of Data Requests in the above-referenced matter.[1]

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.

[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.

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 6th day of April, 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 4/6/2023

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Division 4-1

Request:

Mr. Bonenberger's testimony discusses affordability (page 5). What is the PPL ranking among US electric utilities relative to retail rate level? Also, what is the RIE ranking among US electric utilities relative to retail rate level?

Response:

When comparing the 190 "Investor Owned Utilities" sorted from lowest to highest price, PPL Electric Utilities Corporation ("PPL Electric") ranks 138 and The Narragansett Electric Company ranks 174. Expanding the analysis to all utility types sorted from lowest to highest price, out of 1,598 utilities, PPL Electric ranks 1,286 and The Narragansett Electric Company ranks 1,544.[1]

[1] https://www.eia.gov/electricity/sales_revenue_price/pdf/table10.pdf

Division 4-2

Request:

Mr. Bonenberger's testimony references SAIFI (page 5, footnote 1). Provide the IEEE 1366 standard SAIFI, SAIDI and CAIDI statistics for the past 5 years for RIE and PPL, and for each utility, compare the results to the IEEE 1366 standard statistics for the NE England region.

Response:

The IEEE SAIFI, SAIDI and CAIDI for Rhode Island Energy and PPL Electric Utilities Corporation ("PPL Electric") are provided below for the years 2018 - 2022. The 2021 IEEE reliability statistics for the New England Region are also provided.[1] This region includes reliability statistics from Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

Rhode Island Energy

Year	IEEE SAIFI	IEEE SAIDI	IEEE CAIDI
2018	0.915	65.45	71.52
2019	0.937	67.47	71.97
2020	0.870	68.47	78.70
2021	0.873	68.21	78.11
2022	0.808	62.62	77.50

PPL Electric

Year	IEEE SAIFI	IEEE SAIDI	IEEE CAIDI
2018	0.736	82.5	112.1
2019	0.661	74.3	112.5
2020	0.689	68.6	99.6
2021	0.684	84.6	123.7
2022	0.738	89.3	121.0

[1] https://www.eia.gov/electricity/annual/html/epa_11_02.html

Prepared by or under the supervision of: Wanda Reder

New England Region

Year	IEEE SAIFI	IEEE SAIDI	IEEE CAIDI
2021	1.013	104.1	102.8

Prepared by or under the supervision of: Wanda Reder

Division 4-3

Request:

Referencing page 21 of Walnock & Reder testimony, what land availability analysis has been completed to support the RIE projections for increased solar generation per year? Provide a copy of the study if one has been performed.

Response:

The Company did not perform a land availability study to support the Rhode Island Energy scenario for increased solar generation per year. That scenario, however, aligns with land availability studies performed by others, such as the Rhode Island Office of Energy Resources ("OER") Solar Siting Opportunities for Rhode Island study.[1] That study found the technical potential in Rhode Island to be "between 3,390 megawatts (MW) and 7,340 MW." The Company's scenario would equate to roughly the average of the technical potential.

See the Company's response to Division 3-22 for additional information responsive to this request.

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[1] https://www.synapseenergy.com/sites/default/files/Solar_Siting_Opportunities_for_Rhode_Island_19-076.pdf

Prepared by or under the supervision of: Wanda Reder

Division 4-4

Request:

Referencing page 21 of Walnock & Reder testimony, what roof top availability in square feet or other analysis did the Company perform to support its projections of future roof top solar generation installations?

Response:

The Company did not perform a roof top availability study; however, rooftop solar potential was considered within the Rhode Island Office of Energy Resources ("OER") Solar Siting Opportunities for Rhode Island study.[1] The OER report found a total potential of 2,580 MW and a technical potential of 850 MW of roof top solar.

[1] https://www.synapseenergy.com/sites/default/files/Solar_Siting_Opportunities_for_Rhode_Island_19-076.pdf

Division 4-5

Request:

Page 13 of Walnock & Reder testimony discusses the fact PPL will be interfacing RIE AMF with the PPL ADMS. Mesh network is also discussed on page 31. What will be the telecommunications link between RIE and PPL ADMS? When will the communication link be installed? What will be the backup communications link between RIE and PPL if the main communications system fails?

Response:

The gateways for Rhode Island Energy's radio frequency ("RF") mesh communication will be connected using cellular with redundant national carrier connections into Rhode Island Energy's primary and secondary cloud advanced metering functionality ("AMF") systems. The cloud AMF systems will be redundantly connected to the s advanced distribution management system ("ADMS") environments using multiple physical points of presence.

The main telecommunications link between Rhode Island Energy and the PPL ADMS is targeted to be operational by the end of March 2024 in conjunction with the planned commencement of the AMF network deployment.

Redundancy has been designed into the communication architecture to provide back-up capability in the case of a communication failure. For example, Rhode Island Energy's cloud AMF systems are redundantly connected to the ADMS environments using multiple physical points of presence and the AMF cloud solution uses a primary and a disaster recovery datacenter that will be redundantly connected to PPL's primary and secondary environments.

Division 4-6

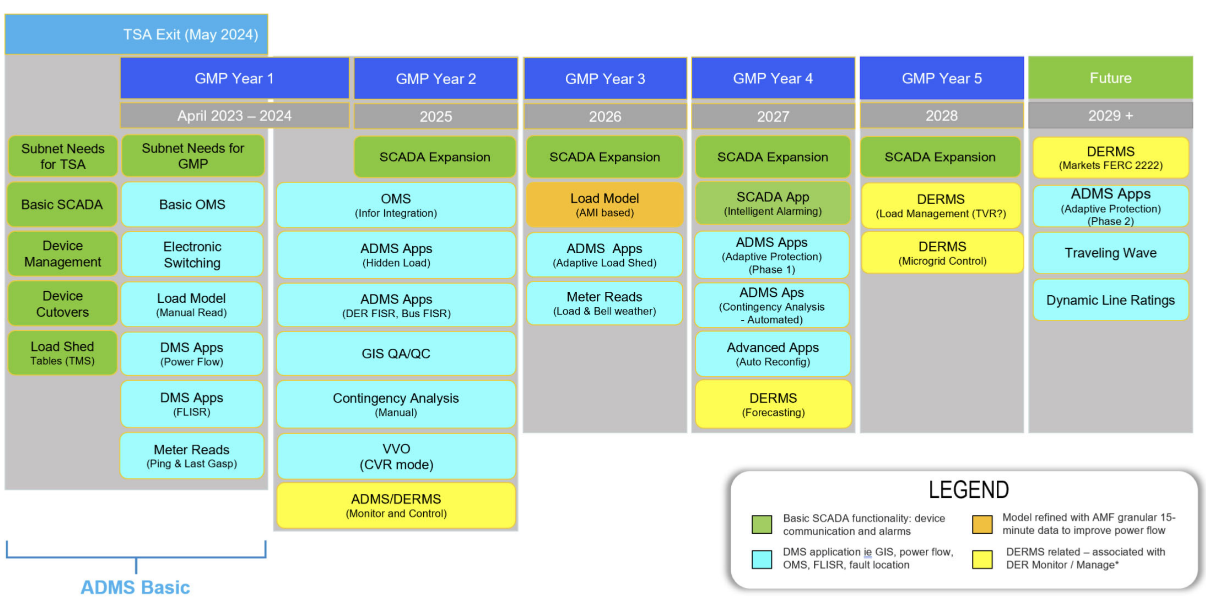
Request:

PPL is providing ADMS "Basic". When will the more advanced ADMS functionality be made available to RIE?

Response:

The ADMS and the Operational Timeline was provided in the Grid Modernization Plan ("GMP") as Figure 6.6 at Bates page 131, and is also provided below. The figure shows the timing of the advanced distribution management system ("ADMS") functionality, which is planned to be released in six (6) groups.

Figure 6.6: ADMS and Operational Functionality Timeline



Division 4-7

Request:

RIE proposes to install meters with a remote disconnect/reconnect feature. How much more expensive is this meter than the meters without this feature? Provide the details of the study and BCA which support the added expense for the meter with remote disconnect/reconnect capability.

Response:

Advanced metering functionality ("AMF") meters with a remote disconnect/reconnect switch are less expensive than AMF meters without the feature. Based upon an estimate provided by Rhode Island Energy's proposed AMF meter vendor, for a typical residential or small business customer, it would cost approximately 34% more for an AMF meter without a disconnect switch. Because the disconnect/reconnect feature is now a common practice in the industry, the feature has been incorporated into the standard production line.

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

Division 4-8

Response:

How many disconnects and reconnects were performed each year for the past 5 years? What was the cost to perform these disconnects and reconnects each year? How much was the customer charged for the disconnect/reconnect each year?

Response:

See the table below, which is taken from the Company's response to Division 3-31 for the number of disconnects and reconnects performed each year for the past 5 years.

3-31 - Disconnects & Reconnects

DESCRIPTION	FY18	FY19	FY20	FY21	FY22
EMERGENCY INVESTIGATIONS - NO ELECTRIC SERVICE, ABNORMAL VOLTAGE	1,446	1,792	1,155	237	576
TURN OFF - METER (METER - OFF/LOCKED)	5,928	6,319	5,163	968	1,336
TURN ON - METER	28,556	26,158	23,162	4,237	10,829
TURN OFF - NON-PAYMENT	42,397	43,462	43,782	91	7341
INSTALL/REMOVE - METER	4,168	5,638	3,359	2,971	3,385

The cost to perform these disconnect and reconnects each year is not readily available, and Rhode Island Energy does not track this data.

Currently there is no fee charged to connect a new customer and no fee that is charged to disconnect. Residential and commercial customers are charged a reconnection charge of $32 for restoration of service following a discontinuance of service in accordance with the Company's electric tariff.[1]

[1] *See* Section 21 of the Terms and Conditions for Distribution Service, R.I.P.U.C. No. 2243 available at https://www.rienergy.com/media/pdfs/billing-payments/tariffs/ri/neco-tcs-dist-svc_ripuc_2243.pdf.

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

Division 4-9

Request:

On page 18 of Mr. Bonenberger's testimony, he discusses PPL being one of the first utilities in the country to use automatic reclosers system-wide and ADMS software in conjunction with AMF meter information. Provide a detailed description of all these functions and what support PPL has to indicate it was one of the first utilities to do this. Also, does PPL mean one of the first investor owned utilities, or one of the first utilities among all electric utility classes (private, IOU, cooperative, municipal and PUD)?

Response:

See the Company's response to Division 3-24, which is attached to this response as Attachment 4-9-1, for evidence that PPL is "... one of the first utilities in the country to use automatic reclosers system-wide and ADMS software in conjunction with AMF meter information." Unless otherwise specified, the awards and recognitions identified in that response are with respect to all electric utility classes.

The functionality that the Company is referring to for the use of automatic reclosers system-wide and ADMS software in conjunction with AMF meter information is described in Section 6.4 of the Grid Modernization Plan filed in Docket No. 22-56-EL ("GMP") at Bates page 144-146. *See* Attachment DIV 4-9-2. The capability described is based upon functionality available at PPL Electric Utilities Corporation.

The Narragansett Electric Company
d/b/a Rhode Island Energy
Docket No. 22-49-EL
In Re: Rhode Island Energy Advanced Metering Functionality Business Case and Cost Recovery Program
Responses to the Division's Third Set of Data Requests
Issued on March 9, 2023

Division 3-24

Questions on Bonenberger Testimony

Request:

[Bonenberger testimony] Please provide data in support of the statement that PPL is "...one of first utilities in country to use automatic reclosers system-wide and ADMS software in conjunction with AMF meter information,…ultimately top decile performance".

Response:

Since 2010, PPL Electric Utilities Corporation's ("PPL Electric") strategy has been to invest in remote operation and monitoring to improve reliability and facilitate the move toward condition based maintenance. Around 2011, PPL Electric began distribution automation investments to improve sectionalization, which led to a replacement of its three-phase hydraulic reclosers with communication-enabled vacuum circuit reclosers that started in 2015.

The system-wide automation investment resulted in national recognition that continued over time, highlighting how leadership and innovation were delivering business results. For example, in 2016, T&D World Magazine published an article,[1] "PPL Electric Utilities Introduces Automated Power Restoration System." Systemwide installation of advanced field devices were the foundation for fault isolation and service restoration ("FISR") and other advanced distribution management system ("ADMS") development. Second-generation advanced meter reading infrastructure was installed from 2015 to 2019. By 2019, PPL Electric was being recognized for leadership in the marketplace to innovate. As an example, the Smart Electric Power Alliance ("SEPA") provided PPL Electric with recognition of the "Investor-Owned Utility of the Year."[2] The award recognized PPL Electric for the creation of the next generation of advanced DMS functionalities through its Distributed Energy Resource Management System ("DERMS"). The same year, PPL Electric was awarded the 2019 ReliabilityOne™ Most Improved Utility Award.[3] In 2020, T&D World Magazine published an article, "PPL Smart Grid Tops One Million Avoided Customer Outages Since 2015,"[4] which

[1] https://www.tdworld.com/smart-utility/article/20966649/ppl-electric-utilities-introduces-automated-power-restoration-system
[2] https://sepapower.org/knowledge/sepas-2019-power-player-award-winners/
[3] https://www.northcentralpa.com/business/ppl-electric-utilities-receives-most-improved-utility-award/article_d35d5dfc-0cd1-11ea-acb7-cb94524d8173.html
[4] https://www.tdworld.com/smart-utility/article/21140940/ppl-smart-grid-tops-one-million-avoided-customer-outages-since-2015

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summarized PPL Electric's journey to avoid outages with smart grid investments. One of the more recent recognitions is the 2022 POWER Magazine Smart Grid Award Winner,[5] which states "PPL Electric was the first utility to centrally install FISR across its entire service territory to automate restorations. That network of smart devices, coupled with GE's advanced software system (ADMS), has assisted PPL Electric in creating an autonomous, self-healing grid. In fact, since 2015, PPL Electric's smart grid has helped prevent more than 1.4 million customer outages. And, in 2021 alone, customers experienced 34% fewer outages compared to the average over the prior five years."

This wide array and ongoing national recognition showcase PPL Electric's leadership and industry innovation for smart grid deployment, which includes the integration of system-wide recloser deployment and AMF that is fully integrated with ADMS.

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[5] https://www.prnewswire.com/news-releases/ppl-electric-utilities-earns-2022-power-magazine-smart-grid-award-301611877.html

Investments is $10.7 million.

ADMS – DERMS application is used in conjunction with DER Monitor/Manage field devices to access inverters. The "Reference Case" for the No Grid Modernization Alternative in the Distribution Study (see Section 5) assumes the Company would need to curtail renewable DG anytime the estimated maximum seasonal DG output of the installed capacity was predicted to exceed the design limitations of the system. This would result in an average renewable DG seasonal curtailment of 17.7% of its annual energy output in 2030 and 40.4% in 2040. The Distribution Study assumed the Grid Modernization alternative would utilize DER Monitor/Manage in conjunction with energy shifting techniques to reduce annual DG curtailment approximately to 0.7% per year in 2030 and 4.4% in 2040. This DER Monitor/Manage functionality will maximize renewable energy production, optimize the use of T/D infrastructure, avoid new infrastructure spend, improve the customer experience, improves power quality, and increases hosting capacity.

Several components will be used for DER Monitor/Manage involving interconnecting DER to the electric distribution system, communicating to DER management devices, receiving and integrating operational feedback from DER for system analysis, calculate dynamic operation settings for DER, and manage settings changes as needed. See Section 7 for more details.

6.4 GMP Roadmap: Advanced Field Devices

As mentioned earlier, solutions for the near-term Foundational Investments include advanced field devices. The total estimated investments for advanced field devices is presented in Figure 6.13.

Figure 6.13: Foundational Investments Advanced Field Devices

Program Category	FY23	FY24	2025	2026	2027	2028	Total
Total Recloser Cash Flow	$ 17,760,000	$ 25,779,600	$ 26,372,531	$ 26,979,099	$ 27,599,618	$ 7,081,011	**$ 131,571,859**
Total Cap Bank and Regs Cash Flow	$ 5,150,000	$ 6,956,400	$ 6,750,112	**$ 6,905,365**	$ 6,998,475	$ 1,120,413	**$ 33,880,764**
Total Electromechanical Relay Cash Flow	$ 3,405,000	$ 4,342,635	$ 6,687,320	$ 10,153,231	$ 8,472,589	$ 8,357,406	**$ 41,418,181**
	$ 26,315,000	**$ 37,078,635**	**$ 39,809,963**	**$ 44,037,694**	**$ 43,070,682**	**$ 16,558,830**	**$ 206,870,805**

Near-Term:

Advanced Capacitors and Regulators: With current levels of DER penetration, dependence on a daily load cycle is no longer possible and the need for on-site sensing is increasing. In response, the Company has revised its standard capacitor control to an electromechanical relay that is activated based on current (i.e., amps) and voltage (i.e., volts) at its location and switches the capacitor on or off as necessary. Accelerated deployment of smart capacitors and regulators with advanced controls will provide voltage and reactive power control to enable management of voltage along the distribution feeder within required ANSI voltage standards. The Foundational Investment for advanced capacitors is based on replacing or upgrading 808 capacitors and for regulators the investment is based on replacing 80 regulators.

For a customer's electrical equipment to operate as expected, it must be connected to a source that is operating within an allowable voltage range which is +/- 5% of the nominal value. For example, nominal delivery voltage may be 120 volts for a residential customer with an acceptable range of 114 to 126 volts. Coincident voltages along the distribution system will vary by location on the feeder, and the voltage at any delivery point will also vary with time.

In the past, voltage regulation was relatively predictable. With one-way power flows, voltage tended to "drop" from the head-end of the feeder to the remote-ends of the feeder due to the resistance of the wires and the distribution of load along them. Key variables for distribution planners to consider in determining how much voltage drop to plan for are a feeder's load profiles and electrical impedance. To compensate for this voltage drop, capacitors and voltage regulators have traditionally been installed to boost the voltage to stay within the required voltage range. For capacitors, a planning rule of thumb was to install "Fixed" capacitors (which are always on) to accommodate the voltage drop at minimum load levels and "Switched" capacitors to compensate for voltage drops at peak load levels. Since electrical resistance of the system and the load cycles were very predictable, the control settings on capacitors and regulators were simple, autonomous, and only needed to be adjusted occasionally in concert with periodic planning reviews. An example of a simple time clock control is shown in Figure 6.14 along with a new programmable-type control unit.

Figure 6.14: Time Clock Control & New Programmable Logic Control Components

Simple autonomous settings are insufficient for Rhode Island Energy to maintain compliance with voltage standards for modern-day feeders with a high level of intermittent renewable DG that cause significant voltage fluctuations. Generation-based DER, such as solar and wind DG, are forecasted to create overvoltage during light load periods, while load-based DER, such as EV charging, are forecasted to create under-voltage issues during peak load periods. While the examples provided in Figures 6.15 and 6.16 present voltage issues, the Company anticipates these issues will be systemic by the year 2030, as these issues are arising in isolated areas already. Likewise, voltage constraints are being identified in interconnection studies and are limiting hosting capacity for many new interconnection applications.

Figure 6.15: Peak Load, Modeled Week of July 21-27, 2030

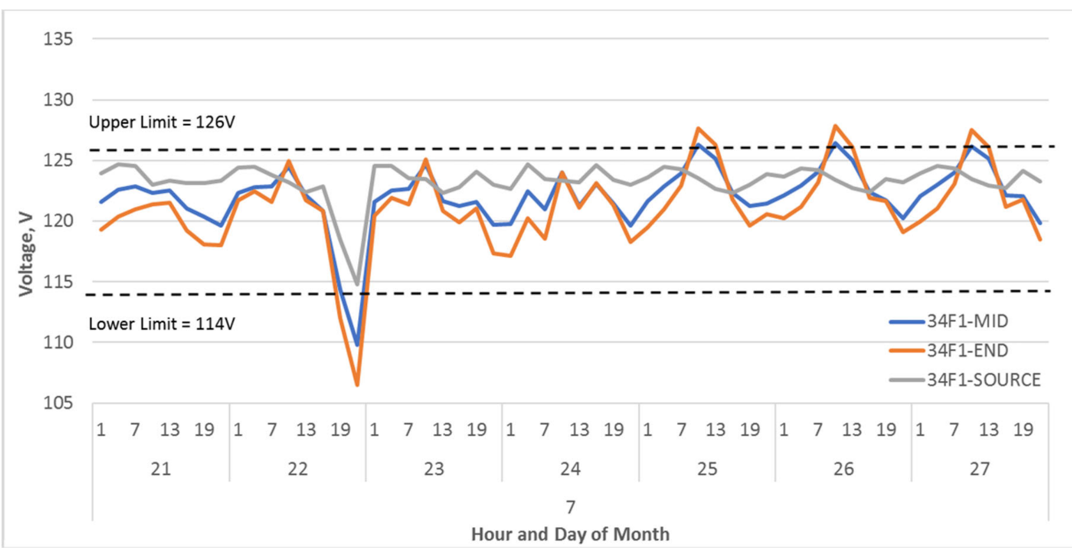


Figure 6.16: Light Load, Modeled Week of May 21-27, 2030

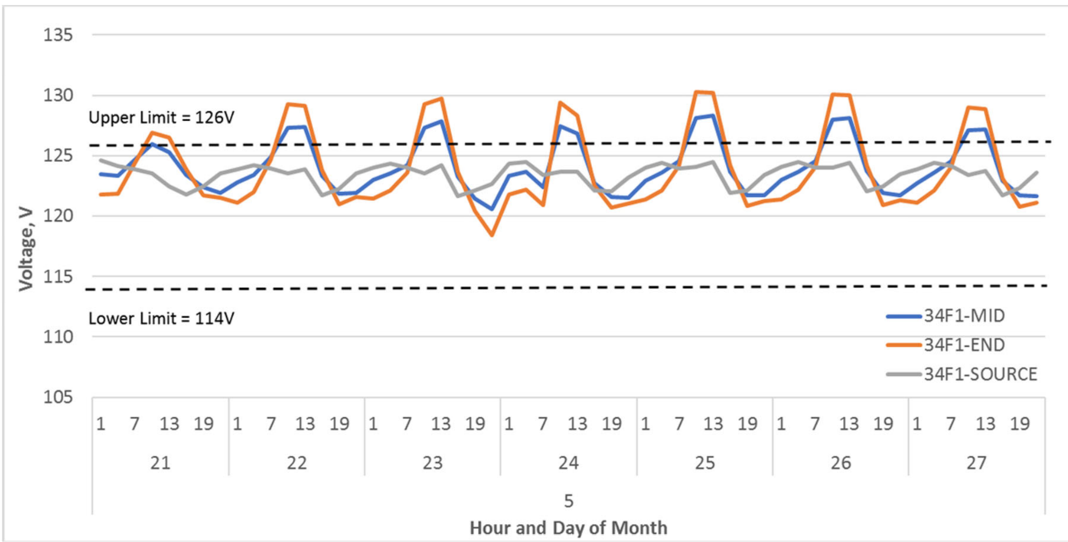


Figure 6.17: Example Overvoltage and Under-Voltage Risks
(Feeder – 34F1; Forecast Year – 2030; Scenario – High DER; Voltage basis –120V nominal, ANSI normal +/- 5% = 126V upper limit, 114 V lower limit)
Load Swing, Modeled Week of January 21-27, 2030

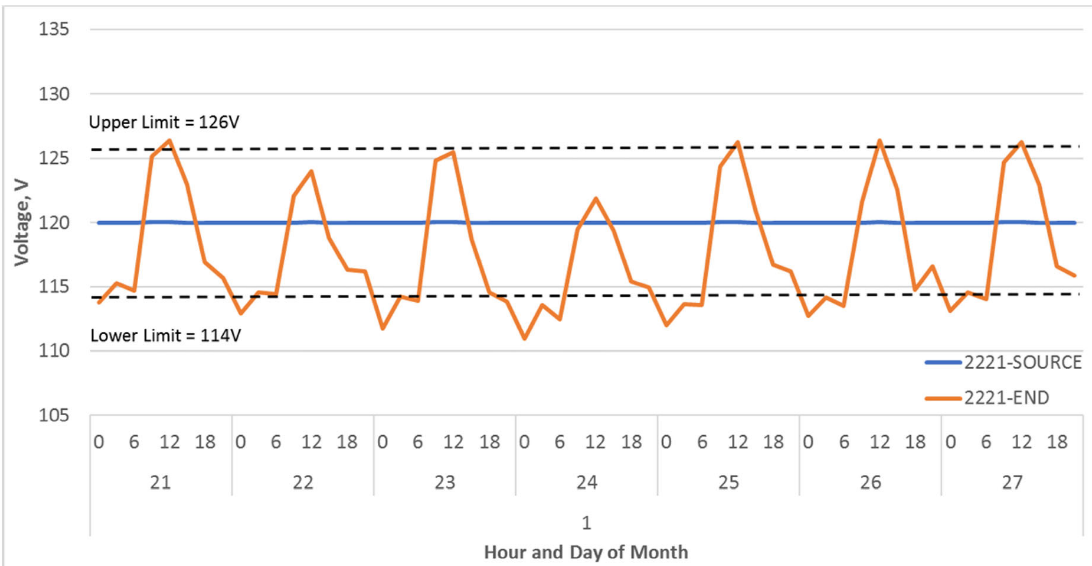
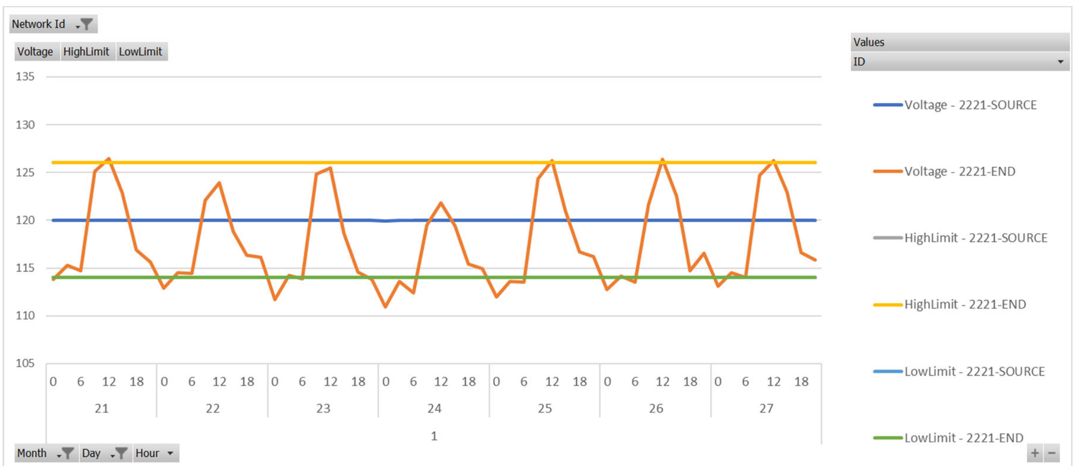


Figure 6.18: Example Sub-Transmission Overvoltage and Under-Voltage Within Same Day
(Line – 2221; Forecast Year – 2030; Scenario – High DER; Voltage basis – 120V nominal, ANSI normal +/- 5% = 126V upper limit, 114 V lower limit)



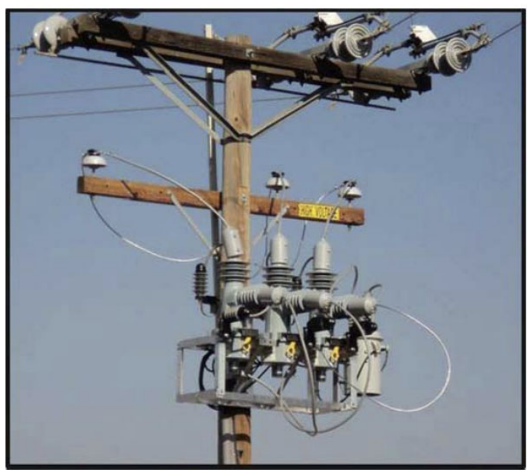
To alleviate these issues, the proposed Advanced Capacitors and Regulators would adjust system voltages up and down in a dynamic manner to accommodate the variable output of DER technologies. For example, as solar DG output increases system voltage, capacitors would switch off and regulators would adjust tap positions to accommodate the voltage change within the acceptable range. As solar DG output decreases and residential EV charging increases in the evening, the capacitors would switch back on and the regulators would readjust to address the voltage drop.

Smart capacitors and regulators are scheduled to be installed starting in 2023, though the benefits from VVO start occurring in 2026 after the granular AMF meter information and ADMS -VVO software is available. The existing VVO deployment on select feeders will be converted to ADMS. Areas of highest compliance risk and high DER penetration will be targeted. Existing fixed capacitors will either be by-passed or modified with advanced controls to eliminate causes of high voltage during minimum load conditions. All existing switched capacitor banks without advanced controls will be modified to include advanced controls. New smart capacitors and regulators will be added at strategic locations to minimize compliance risk and to enable VVO benefits. The accelerated deployment of advanced capacitors and regulators will enable VVO, starting in 2026, which results in significant savings, and operational benefits.

Advanced Reclosers: Advanced Reclosers are switches that can interrupt power flow in response to a short circuit and then automatically allow power flow to resume a short time later.

The foundational GMP investment for advanced reclosers is based on replacing 1,561 reclosers. Typically deployed throughout a distribution grid, reclosers are used to isolate customer outages due to temporary faults via automatic sectionalizing and restoration. The Advanced Field Device is a breaker equipped with a mechanism that can automatically close after it has been opened due to a fault. The programmable electronic controls allow close coordination with other devices, and enhanced sensing capabilities, that when enabled with communications, can send operating information and a field crew can be dispatched to fix a fault when the reclosing operation doesn't eliminate the problem.

Figure 6.19: Recloser on a Distribution Pole



FLISR reclosers will be pole-mounted remote supervisory reclosing and switching devices. They will also be able to report fault current to ADMS, which provides the ability to identify the possible location of the fault. If the recloser determines that there is a permanent fault after multiple attempts to reclose, the device will open and remain open, then communicate information about the fault event to ADMS. The ADMS/FLISR functionality is the critical operating system for Reliability Management. FLISR technologies and systems involve advanced reclosers/switches, line monitors, communication networks, ADMS, OMS, SCADA systems, grid analytics, models, and data processing tools. These technologies work in tandem to automate power restoration, reducing both the impact and length of power interruptions.

FLISR identifies a fault on the electric grid and minimizes its impact on the customers as quickly as possible. It is an automatic process that identifies the fault, isolates it, and redirects power to as many of the customers affected by the fault as possible. The fault is identified using sensing from Advanced Reclosers, AMF meters, Advanced Capacitor banks, and Microprocessor relays that monitor the flow of electricity and measure the magnitudes of fault currents. As soon as the fault is identified, advanced reclosers are opened to isolate the fault and then closed to redistribute power to the affected customers.

Safe and reliable service is provided by ensuring equipment operated within its rated capacity and that faults on the system are cleared in a fashion that prevents damage to equipment and limits service interruptions to as few customers as possible. Increasing customer DER adoption adds complexity to managing distribution system loading and the protection systems. This requires sensing from field devices, ADMS/FLISR software and Advanced Reclosers on the distribution feeders. In addition to having Reclosers isolate faulted line segments and tie line reclosers to allow transferring customers to adjacent feeders, these devices will become increasingly important to sensing systems conditions, balancing load and generation on the distribution system, and curtailing commercial sized DER, when needed. They will also need to be equipped with the ability to perform ADMS-based protection to dynamically adjust protection schemes based upon the dynamics of the system. Advanced Reclosers support or enhance several other key functionalities, including Observability (Monitoring and Sensing), Power Quality Management, Grid Optimization, and DER Monitor/Manage.

Recloser installations start as soon as 2023 and the corresponding reliability gains are expected to start shortly thereafter beginning in 2024. The accelerated installation of the Foundational Investments will allow for Reliability performance improvements as soon as possible (see Section 1.9). This capability is enabled by having ADMS Basic available to Rhode Island Energy in 2024.

A reliability analysis was performed and the results show that reliability will increase up to 30% by installing reclosers and using them in conjunction with the ADMS- FLISR application available in ADMS Basic. The assessment to determine the reliability improvement compared mainline outage reliability data averaged over the last five years to that expected if reclosers are placed using a segmentation criterion of 500 customers between devices.

The calculation uses Blue Sky Day numbers used in the table below. To determine the reliability improvement:

- **Existing:** 207,191 customers that experience a mainline interruption.
- **With Reclosers:** If reclosers are installed across the system using the 500 customer segmentation criteria, then there would be 79,500 customers impacted by the same 159 events using reclosers. (500 customers per event x 159 events = 79,500)
- **Results:** The customer interruptions saved using reclosers is 127,691 (207,191 – 79,500).
- **SAIFI impact:** Divide the customer interruptions saved by the average customers that are served 127,691/495,622 resulting in an estimated SAIFI improvement of 26% annually.

Analysis was also done "with major storm" to indicate that reclosers positively impact resiliency. Using the methodology described above, the number of which show that customers that would be impacted by severe weather would be reduced. Also, if a customer does realize an outage, the time it takes to restore them will be less. As mentioned above, in addition to the reliability benefits, the reclosers offer numerous other advantages such as improved system visibility, flexibility for system configuration, enhanced protection capability, voltage data to improve volt/VAR optimization analysis, and a host of operational efficiencies.

Figure 6.20: Rhode Island Energy Reliability Impact with and without GMP Reclosers

Average Annual Reliability Impact With & Without GMP Reclosers Circuit Breaker and Recloser Events January 2017 through December 2021				
Day Type	Blue Sky Day *		Major Storm (IEEE TMED)**	
Customers per recloser	500	1000	500	1000
RI Energy Average Cust Served	495,622	495,622	495,622	495,622
# of events	159	159	122	122
CAIDI (min)	66	66	813	813
Total CI	207,191	207,191	143,120	143,120
Average CI / event	1,303	1,303	1,171	1,171
CI with GMP Reclosers / event	500	1,000	500	1,000
Total CI with GMP Recl.	79,500	159,000	61,100	122,200
Delta CI	**127,691**	**48,191**	**45,825**	**15,690**
SAIFI improvement	0.258	0.097	0.092	0.032
Delta CMI	**8,405,116**	**3,180,606**	**37,241,256**	**12,750,894**
SAIDI Improvement (min)	16.96	6.42	75.14	25.73

** Assumes automated switching takes less than 1 min. **Assumes 75 % successful operations during storms.*

This assessment indicating that the SAIFI reliability improvement of approximately 26% for Rhode Island Energy with reclosers installed using the 500 customer segmentation criteria aligns with estimated benefits published by DOE where four projects reported SAIFI improvements of 11 – 49%.[75] It also aligns with PPL Electric's experience where they have realized SAIFI improvement of approximately 28% since installing advanced recloser throughout the service area using the same segmentation criteria of 500 customers in conjunction with FLISR (see

[75] *See* https://www.energy.gov/sites/prod/files/2016/10/f33/Distribution_Reliability_Report_-_Final_Dec_2012.pdf

Section 1.8). A 26% SAIFI improvement was used as an input in the interruption Cost Estimator (ICE) calculator[76] for the BCA benefit calculation.

Microprocessor Relay Upgrades

Substation relays provide the logic inside a substation for when and why a breaker opens. Modern relays are multi-functional and have multiple protection functions programmed into them. The Foundational Investment for relays is based on replacing or re-programming over 400 relays. The investment also includes dollars for engineering of substation rebuilds. The primary use-case for a relay on a feeder breaker is to monitor the status of the distribution system and trigger an open command to the breaker in the event of a fault on the system. These relays can also capture important fault information which will be sent to ADMS for the Fault Location application. Replacing the existing and obsolete electro-mechanical relays on each distribution feeder with microprocessor relays will add significant additional sensing data to the ADMS system to improve visibility and situational awareness. Significant swings in loading and the prevalence of two-way power flows caused by renewable DG will require more adaptive relay protection schemes to properly coordinate circuit breakers to ensure worker safety and the reliable operation of the grid.

Traditional distribution protection schemes with electro-mechanical relays utilize phase and/or ground overcurrent relays to detect short-circuit faults. Coordination is achieved through time-delayed operation. While this is a proven and effective method for clearing "traditional" fault types, such as a solid tree contact, it leaves gaps for restricted faults, such as a downed conductor – critical to public and worker safety, and arc flash protection, DER and ride-through coordination for bulk system stability, and general customer experience via voltage dips (brown outs) or interruptions to service. The goal of advanced protection schemes at Rhode Island Energy is to cover these gaps while also building toward a future where the grid is fully adaptive to system conditions, including protection schemes. There are near-term and future term capabilities, as follows:

Near-term:

These are benefits achieved at PPL, which will be gained at Rhode Island Energy:

– *Downed-Conductor Detection:* PPL has utilized SEL's Arc Sense algorithm and built patented logic on top of it to build a system for automatic isolation of downed conductor events. The success rate at PPL is around 60%, with each event involving the public in close

[76] *See* https://icecalculator.com/home

proximity to the downed wire. Therefore, there is confidence that dozens of lives have been saved.

- *Worker Safety:* PPL utilizes hot-line tag ("HLT") on all distribution devices to protect workers from arc flash conditions as described in OSHA 1910.269. This involves instantaneous clearing and no reclosing to limit arc flash to the minimum incident energy. Since this was activated in 2016 there have been three PPL incidents where workers were subjected to flashes and serious injury was avoided with HLT activated.

- *DER and Ride-Through:* As the grid transitions into a distributed energy future, inertia in the system is reduced (i.e., fewer spinning generating units). It is therefore important for DER to remain online as long as possible during system disturbances to promote bulk power stability. Rhode Island Energy will establish ride-through DER settings balancing local system and system interests. If ride-through philosophies change over time, updated ride-through settings can be installed remotely.

- *Local Fuse Savings*: Traditional fuse savings schemes happen on 3-phase devise and impact hundreds or thousands of customers. Rhode Island Energy will work toward eliminating the 3-phase schemes and moving to local fuse savings via TripSavers at the head of single-phase taps. This improves SAIFI reliability by allowing for more downstream fusing of the taps. It also vastly reduces MAIFI by reducing the number of customers impacted by 90% (only the tap trips to save the fuse instead of the 3-phase device). This has the added benefit of minimizing effect of brown outs by clearing fault locally and as quickly as possible.

Future-Term:

Adaptive Protection: ADMS software that will support implementation of adaptive protection systems that can respond to changing fault conditions to properly coordinate circuit protective devices to ensure worker safety and the reliable operation of the grid. This is a long-term project still in progress, but involves building an automated ADMS system that can adapt protection settings to changing system conditions. This application would automatically check if protective devices can clear all faults anywhere on the feeder. The goal is to make sure protection can clear faults when a feeder is in an abnormal state due to switching. In addition, the application will check the device pair coordination of all protective devices on a feeder based on protection settings and identify miscoordination. If there is a violation, it would check the alternate setting groups to see if another setting would provide coordination. This requires the relay and recloser settings to be defined in the ADMS database along with the alternate settings. The protection settings (e.g., fuse curves) would also be imported into the ADMS data. This first phase of the ADMS adaptive protection functionality is planned to be available in 2027 and the second phase is scheduled in 2029. Without GMP investments in ADMS, Advanced Field Devices, Microprocessor Relays, and an ADMS-based Protection & Arc Flash App, a labor-intensive process to make the system safe for workers would be required, especially under high DER adoption scenarios. In cases where DER could create protection system coordination issues or negatively affect arc flash levels, field crews would need to be dispatched to reprogram protection devices, rearrange the system, or even disconnect DER at certain times for safety reasons.

Dynamic Line Ratings: ADMS can use real-time weather conditions such as temperature and wind to increase line ratings which can improve line operation capabilities. Dynamic line rating can benefit renewable operators because rather than being asked to curtail at times of peak production due to congestion, if the peak coincides with windy or cold conditions, they could continue to produce if the conductor capacity ratings can be increased to carry the production because of conductions are cooler than originally assumed.

To implement the relay upgrades, a relay inventory was completed. Relays to be upgraded in the Foundational Investments represent approximately 17% of the total population. As a result, there will be ongoing relay upgrades performed in the future-term as well, both opportunistically and on a planned basis to achieve the desired operations for safe and reliable service. Efforts are underway to compare PPL protection philosophy with practices in Rhode Island and to apply PPL reference standards to the extent applicable. Preliminarily, Rhode Island Energy equipment looks similar to that used in other PPL jurisdictions; however, programming is very different and will require significant upgrades to integrate with ADMS FLISR approach for Reliability Management in Rhode Island. Alignment with FLISR and ADMS requirements and the emerging need of protecting equipment encountering multi-directional power flow is driving the urgency for having the microprocessor relay upgrades in the Foundational Investments.

6.5 GMP Roadmap: Communications

Rhode Island Energy is developing a communications network that includes a Fiber Backhaul in the Foundational Investments. The estimated cost of this investment is presented in Figure 6.21.

Figure 6.21: Foundational Investments Communications (Fiber)

Program Category	FY23	FY24	2025	2026	2027	2028	Total
Total Distribution Fiber Cash Flow	$ 8,270,000	$ 11,580,000	$ 18,240,000	$ 15,590,000	$ 8,160,000	$ 8,160,000	**$ 70,000,000**
Transmission Fiber	$ 3,285,714	$ 4,380,952	$ 7,666,667	$ 7,666,667	$ -	$ -	**$ 23,000,000**
Total Communications (Fiber)	$ 11,555,714	$ 15,960,952	$ 25,906,667	$ 23,256,667	$ 8,160,000	$ 8,160,000	**$ 93,000,000**

The communications network consists of the capability to simultaneously access diverse types of endpoints on the electric system - each with their own performance requirements. The strategy provides a two-way communication network that serves multiple "tenants," which include but are not limited to,

Division 4-10

Request:

Referring to pages 7, 26 and 36 of the Walnock and Reder testimony concerning voltage data, explain how the voltage data from the AMF meter will be used and the exact benefits of that data to the customer. Also, explain how the voltage data from the 525,000 AMF meters will be effectively processed and used.

Response:

The proposed advanced metering functionality ("AMF") meters record voltage readings on 15-minute intervals. The 15-minute AMF voltage data is transmitted from each AMF meter through the radio frequency ("RF") mesh communication network to the Company's headend systems. The data will then be sent to the advanced distribution management system ("ADMS") and archived for further analysis. This allows the Company to analyze 8760 hours of data annually to ensure service voltage remains within ANSI C84.1 and 815-RICR-30-00-1 standards during peak and light loading periods. To the extent that the voltage exceeds the operating minimum/maximum threshold settings, the meter also can communicate voltage events through advanced reporting in near-real time to alert operations personnel of a system problem. The Company can then take action to mitigate the identified voltage exceptions before customers contact the Company to report concerns. This is a significant improvement over the current process, which requires that customers initiate a voltage complaint that prompts a Company investigation before taking action to mitigate voltage exceptions.

Additionally, comprehensive historic voltage measurements from AMF can support various distribution-level applications, such as predictive failure analytics and feeder voltage profiling, to determine how to adjust voltage control devices. The Company can use the voltage data as an input into the volt/var optimization ("VVO") application for increased energy efficiency and reduced line losses. AMF voltage data can be used as a leading indicator for identifying overloaded or failing equipment prior to customer outages. Voltage readings at the customer premise allow for more accurate system load studies and distributed energy resources ("DER") impact studies. Currently, voltage measurements are limited to a relatively small number of devices installed along the circuit. The Company uses engineering tool assumptions to estimate the voltage at the edge of the electric distribution system. By integrating AMF meter data with these tools, the Company can promptly address voltage issues, increase study accuracy, lower long-term capital reinforcement costs, boost DER hosting capacity, and improve system reliability.

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Benefits to the customer include improved power quality, increased reliability due to potential avoidance of customer equipment and distribution system component failures, enhanced energy efficiency and reduce cost. The Company can perform advanced analytics on the historical data to monitor trends and detect issues, such as transformer winding failures and deteriorating service connections. Utilizing AMF data to correct potential failures can save the customer a potential backshift outage and reduce O&M by avoiding emergent work that may occur at a time that commands premium labor rates. By having the ability to determine if high or low voltage is on the customer or utility side of the meter, AMF can also prevent unnecessary customer electrician cost and improve power quality for customers.

In addition to the uses and benefits of voltage data mentioned above, in the future it is possible that the Company could use voltage data from meters for voltage stability assessments and, new voltage control schemes that make use of AMF and DER to provide stability at the end-user, which would provide an added reliability benefit to customers.

Division 4-11

Request:

Discuss the various devices on RIE's system that measure voltage, including minimum-maximum voltage meters, and how the data is used for operations, planning and decision making. Explain why additional minimum-maximum voltage meters are not capable of providing the level of data required for future operations, planning and decision making. What incremental value is provided from AMF above what can be achieved with current devices and how does RIE determine that incremental value?

Response:

The Company is limiting the response to this data request to distribution line voltage measurement devices. Distribution substation voltage measurement equipment is not included because substation voltage measurement equipment and how it is used for distribution planning is well-understood and has been used and will continue to be used for decades; it has no impact to the benefits of AMF voltage measurement.

The distribution line voltage measuring equipment includes line regulators, capacitors, and reclosers, which provide the following functionalities:

Line regulators have controls that sense current voltage levels on the source side of the device and then direct a tap changer to increase the voltage on the load side of the regulator to an appropriate level. These regulators can typically adjust the voltage by +/-10%. Many of these line regulators do not have communications or data capture capabilities. They are included as a device in planning models, but these devices do not provide the necessary data to improve planning and decision-making.

Capacitors are shunt devices that inject volt-amp reactive power ("VARs") to raise localized voltage levels. Older capacitor controls include a time clock with no voltage sensing. Newer capacitor controls sense the system voltage at its tap point, and if the voltage is too low, the capacitor will turn on. Similarly, when the localized system voltage gets too high, the capacitor will turn off. The Company has been installing communications equipment with the newer capacitor controls for the past few years and uses the data for planning and decision-making.

The latest reclosers also will include voltage sensing. Specifically, voltage data from advanced capacitors and reclosers that are located on the mainline is used to troubleshoot distributed energy resources ("DER") related issues and to provide operational input for voltage management.

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Additional minimum-maximum voltage meters would not be capable of providing the voltage measurement capability that advanced metering functionality ("AMF") meters can deliver. See the Company's response to Division 4-10 for an explanation of how the granular AMF voltage data will be used and is superior to what is available today because each feeder would have thousands of measuring points coming from locationally distributed AMF meters, as compared to a few voltage sensors periodically located on the mainline. The quantity and dispersed location of voltage sensing from AMF will result in greater measurement accuracy and a better understanding of voltage variability over time. The AMF voltage measurement value was specifically calculated within the AMF BCA as the VVO benefit adder that is described in Section 11.5.3: Volt/Var Optimization ("VVO") Opportunities/Conservation Voltage Reduction benefit, Bates pages 146-148.

Prepared by or under the supervision of: Wanda Reder

Division 4-12

Request:

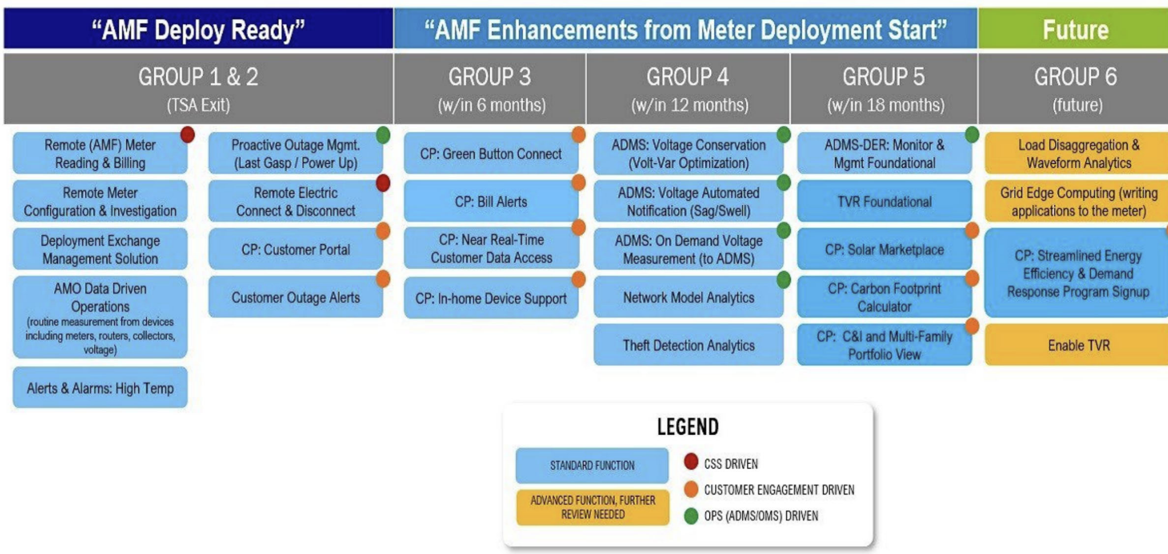
Provide a detailed explanation of how the AMF data is incorporated into the power flow models, how the data will be utilized, and when that will be fully functional.

Response:

Reliable distribution system modeling requires the ability to manage the current state data from the advanced metering functionality ("AMF") meters and other field devices with a power flow representation of the distribution system. The resulting distribution system model can provide operators with an enhanced view of the current state of the distribution system that can improve real-time monitoring, network restoration, outage management, security assessment, volt/var optimization ("VVO") or energy loss optimization, and load control. Currently, there are very few measurements of the current state on the distribution system that are available to the operators, causing a lack of observability. AMF provides the opportunity to significantly increase available measurements by offering data from each smart meter. AMF meter data that can be used to enhance operations is further described in Section 3.4.2 of the AMF Business Case at Bates pages 38-41.

To incorporate the AMF data into the power flow models, the Company will leverage existing platforms already in use in Pennsylvania, as described in Section 2.7 of the AMF Business Case at Bates page 25. In terms of timing for availability, as described in Section 6.2 of the AMF Business Case at Bates page 70, AMF outage detection will be integrated with restoration systems and implemented in tandem with the meter deployment. Therefore, Last Gasp and Power Up alarms from AMF will be available to operators as meters are exchanged and sector acceptance occurs in a given geographic area. Additional functionality will be provided as AMF meters are being installed and sector acceptance occurs in a given geographic area, with releases defined every 6 months following the advanced distribution management system ("ADMS") Basic release. Figure 6.1 in the AMF Business Case provides the AMF Functionality Roadmap (also provided below) with corresponding definitions included in the AMF Business Case at Bates pages 71-74. Functionalities that are noted with a green dot are ADMS related.

Figure 6.1: AMF Functionality Roadmap



Division 4-13

Request:

Provide a full and complete explanation of how the AMF meter data increases outage visibility beyond the existing outage management system notifications. In particular what is the difference between the phone call information that goes into the outage management system and the AMF data. Isn't it true that a recloser or fuse that de-energizes a section of a line results in an outage to every customer on that section of line, and that either phone calls or the AMF data result in the same need to dispatch line personnel? Further, line personnel have to patrol the entire line section to determine the location and cause of the outage and thus the AMF data does not change that process or duration of effort, correct?

Response:

There are two improvement aspects for outage response from advanced metering functionality ("AMF"): outage notification and outage restoration. The Company quantified the value of the benefits from outage notification in the AMF Business Case. The Company quantified benefits from improvements to the outage restoration process in the Grid Modernization Plan ("GMP"), filed in Docket No. 22-56-EL.

AMF Outage Notification Benefit: See the Company's response to Division 3-16. The Last Gasp meter alert functionality enabled by the AMF meters provides advantages over the current methods of outage notification. Currently, Rhode Island Energy relies on customers manually reporting outages by phone call to an agent, through the interactive voice response ("IVR") system, or through a text message. Not all customers affected by an outage take this step, and it can take some time for those customers that are out of power to initiate outage communications to the Company. As a result, the Company's visibility into the scope of the outage is limited and may take some time to become clear, depending upon which customers report the outage and how long the reporting takes. A significant improvement occurs with Last Gasp meter alerts from AMF meters because the meters send notifications of "no power" automatically from all meters affected by the outage as soon as there is a loss of line side power. This provides faster and more complete visibility into the source and scope of the outage. Last Gasp meter alerts have allowed PPL Electric Utilities Corporation ("PPL Electric") in Pennsylvania to respond to and restore outages prior to receiving a call from a customer. From August 2019 through July 2020, PPL Electric was able to restore approximately 19% of outages without receiving a call from a customer based on Last Gasp meter alerts alone. In the two years after that, beginning in August 2020 through July 2022, that number increased to approximately 25%.

AMF Restoration Benefit: AMF also can improve service restoration when the granular AMF data is coupled with grid modernization investments. This is especially helpful when recovering from Major Events.[1] Once power is restored, the AMF meter will use the Power Up functionality to send a restoration message back to the Company as a verification that the AMF meter has power. The Company also can send proactive interrogations ("Pings") to AMF meters to ascertain the status of power to meters. Pings allow the operators to remotely interrogate the status of power at a particular meter location to identify false outage information, precisely dispatch crews for restoration, and confirm that the repairs have been made that allow service to be re-established. Pings also can help identify nested outages so the Company can address them. Nested outages are service outages that may not be visible by operators in the Outage Management System because they are superseded by higher-level equipment outages at transformers and circuits. System operators use both Power Up restoration messages and Pings once the suspected initial outage has been restored to verify that all customers are back in service and that there are no other nested outages present.

The difference between customer phone calls entered into the Outage Management System ("OMS") and AMF meter data transmitted immediately upon a power outage, has been quantified as a 22-minute faster outage notification, on average. See the Company's response to Division 1-17. When a recloser or fuse de-energizes a section of a line, it is correct that it does result in an outage to every customer behind that device, requiring the need to dispatch line personnel; however, with faster notification from the AMF meter, the outage gets into the OMS faster than customer notifications. In addition, when AMF is combined with fault location, isolation, and service restoration ("FLISR"), the increased visibility of the outage location improves dispatch efficiency. Thus, it is incorrect that AMF data does not change the process or duration of effort; it, together with FLISR, minimizes the section of the circuit or line that needs to be patrolled to identify the outage.

[1] The term "Major Event" is used to identify an abnormal event, such as a major storm. In Rhode Island, the Amended Service Quality Plan approved by the Public Utilities Commission in Docket No. 3628 defines a Major Event Day as "[a] day in which the daily system SAIDI exceeds a threshold value, TMED," which is calculated using methodology defined in the IEEE Standard 1366-2012.

Division 4-14

Request:

Explain in detail, if not fully discussed in the answer to DIV 4-13, how AMF enhances reliability and specifically the outage management system and power restoration process if outages are now reported through the OMS.

Response:

See the Company's response to Division 4-13, which fully addresses the question of how advanced metering functionality ("AMF") enhances the outage management system and power restoration process, which inherently makes the electric distribution system more reliable, especially during storms. AMF enhances reliability when used in combination with Fault Location, Isolation, and Service Restoration ("FLISR") automation technology, as discussed in the response to Division 4-13 and Section 1.3 of the AMF Business Case at Bates Pages 8-12. FLISR can change how the distribution system operates by automating the distribution network reconfiguration, minimizing the number of customers impacted by a power outage, and enabling more effective and efficient response to restore service. These reliability improvements are made possible, in part, by Last Gasp and Power Up alert information coming from AMF meters. Using the AMF informational platform for FLISR automation, outages are isolated to small customer blocks using automated distribution switching so that fewer customers experience an outage. Outage information and isolation enable restoration crews to be more efficiently dispatched to pinpointed outage locations, resulting in reduced outage restoration times. AMF enhances reliability in other ways too, such as with enhanced operational functionality that comes from greater visibility to voltage data when used in conjunction with Volt-Var Optimization technology and greater situational awareness that results in better load forecasting and distribution planning, among other things. These functionalities and how they enhance reliability are more fully discussed in Section 3 of the AMF Business Case at Bates Pages 30-42. See also the Company's response to Division 4-16.

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

Division 4-15

Request:

What has been the increase in failure rate, if any, among the existing AMR metering? Provide the quantity of meter failures per year for the past 3 years by type such as AMR meter, electromechanical meter and so on. Additionally, for the same period of time, provide the meter replacements due to test calibration failure and actual failure.

Response:

Rhode Island Energy is in the process of gathering and validating the information sought in this request, but has not yet completed that process. Rhode Island Energy will supplement this response once it has completed that process.

Division 4-16

Request:

Explain in detail why AMF meters versus AMR meters provide RIE with the ability to deliver safe and reliable service to customers as discussed on page 12 of Walnock and Reder testimony.

Response:

Gaining granular visibility of the distribution system through advanced metering functionality-("AMF") provided 15-minute interval readings taken at each meter location is important for reliability so dynamic system conditions can be monitored and understood at any place or level on the distribution system. This added visibility provides insight to the system status for enhanced grid operations and improved outage management capability.

Today, the distribution operators of the electric distribution system in Rhode Island have limited situational awareness of the state of the distribution system on either a granular or locational basis. Automated meter reading ("AMR") meters in Rhode Island are read using the drive-by technology which captures a read that is downloaded to a system for billing every month, providing no real-time visibility to current system conditions. Section 3.1 of the AMF Business Case at Bates page 31 provides a more detailed description of the current state.

AMF provides enhanced operational functionality described in Section 3.4.2 of the AMF Business Case at, Bates page 38. Examples of operational capability improvements from AMF and the granular information it provides to increase reliability includes added situational awareness include, (i) load shifting capability, (ii) improved voltage management, (iii) automated outage notification, (iv) reduced meter failures, and (v) improved asset identification. The Company's responses to Division 4-10, Division 4-12, Division 4-13 and Division 4-14 further describe how AMF meters can contribute to providing safe and reliable service.

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

Division 4-17

Request:

Are the statistics stated on page 18 of Walnock & Reder testimony for investor owned utilities only or is it for all electric utilities in the United States? Also, are the 102 million estimated total number of automated meters installed in the U.S. only for investor owned utilities? If not provide the breakdown by utility type. Additionally, what is the breakdown of the utility type for the 560 utilities?

Response:

The statistics represent the total population of electric meters in the United States. The Federal Energy Regulatory Commission ("FERC") statistic was based upon U.S. Energy Information Administration ("EIA") data representing all electric meters in the United States. The Institute for Electric Innovation defined their dataset as the electric power industry that included investor-owned electric companies, public power utilities, electric cooperatives, and federal utilities. The same is true for Wood Mackenzie: "estimates that the total number of automated meters installed in the U.S. as of the end of 2020 reached almost 102.0M" was sourced from the Wood Mackenzie's Grid Edge Data Hub and the U.S. EIA's Form EIA-861 metering data which represents electric meters for all utility types. The breakdown of utility type for the 560 utilities quoted from Wood Mackenzie is not available. However, provided below are the actual 2020 results of EIA Form 861 data broken down by utility ownership type, which shows 103 million advanced metering infrastructure ("AMI") meters[1] vs. Wood Mackenzie's estimate of 102 million meters for 2020.

Ownership Type	2020 AMI Count
Behind the Meter	126,423
Cooperative	16,369,068
Federal	2,323
Investor Owned	74,007,243
Municipal	8,931,589
Political Subdivision	2,687,487
State	936,193
Grand Total	**103,060,326**

[1] Annual Electric Power Industry Report, Form EIA-861 detailed data files, Advanced_Meters_2020

Division 4-18

Request:

Explain in detail how AMF increases hosting capacity without any increase in system capacity.

Response:

Please see the Company's response to subpart (a) of OER 1-13, which is reproduced below.

Current interconnection analysis uses the distributed energy resource ("DER") nameplate in comparison to localized system ratings with a minimum load value. There is currently no data available to consider the timing of the DER peak to the timing of minimum load. Advanced metering functionality ("AMF") would allow for daily load cycle analysis of existing sites to develop new analysis assumptions considering the actual DER output and minimum load at the time that the DER is peaking. The following cases highlight the opportunity.

- Case 1 – Current analysis method (no time data available)
  - DER Nameplate = 10
  - DER Output = Nameplate = 10
  - System Device Rating = 7
  - Minimum Load =2
  - Hosting Capacity = 7+2 = 9
  - Hosting Capacity < DER Output = Upgrades Required

- Case 2 –11 AM with AMF Data
  - DER Nameplate = 10
  - DER Output = 9
  - System Device Rating = 7
  - Minimum Load =2
  - Hosting Capacity = 7+2 = 9
  - Hosting Capacity = DER Output = No Upgrades Required

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- Case 3 –1 PM with AMF Data
    - DER Nameplate = 10
    - DER Output = 10
    - System Device Rating = 7
    - Minimum Load =3
    - Hosting Capacity = 7+3 = 10
    - Hosting Capacity = DER Output = No Upgrades Required

Division 4-19

Request:

On page 70 of Walnock & Reder testimony there is discussion of volt/var optimization (VVO). RIE has provided several different explanations of VVO in previous conferences and dockets. The Division has heard at least three different scenarios which include: 1) VVO pilot demonstrates significant economic benefit; 2) the level of DER on the system has nearly eliminated the VVO economic benefits and that is why there is little economic benefit lost as a result of the deferral of further VVO installation; and 3) AMF will provide additional economic benefit above that demonstrated from the VVO pilot. These three explanations do not appear consistent. Explain in detail what the actual benefits and expectations of VVO are going forward.

Response:

The Company has recognized and stated that distributed energy resources ("DER") can affect volt/var optimization's ("VVO") economic benefit and that it was appropriate to pause wide-scale deployment as it analyzed these impacts.[1] The Company also has recognized that incorporation of the VVO control system into an Advanced Distribution Management System ("ADMS") can provide benefits that contribute to a reasonable benefit to cost ratio, and thus with the current plans to proceed with an ADMS system, a pause is further justified.[2] Accordingly, the Company's statements are consistent with 1) initial VVO evaluation which concluded the potential for significant economic benefits; 2) refined evaluation which indicated a need for more detailed DER evaluation; and 3) advancements in control systems, which when incorporated into an ADMS system with advanced metering functionality ("AMF") data can maintain economic benefits.

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[1] *See* Rhode Island Energy's Grid Modernization Plan, Docket No. 22-56-EL, Attachment L: Impact of Distributed Generation and Grid Modernization on Volt-Var Optimization Systems, Book 2 at Bates Pages 336-344.

[2] *See* Fiscal Year 2023 Electric Infrastructure Safety and Reliability Plan, Docket No. 5209, Company's responses to Division 1-13 and PUC 1-6 (describing a pause in VVO efforts pending the PPL transition and implementation of ADMS).

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

Division 4-20

Request:

Pages 54-55 of Walnock & Reder testimony indicate that RIE will leverage existing PPL strategic partnerships in deploying AMF including scaling existing PPL vendors coupled with request for proposal "best cost" considerations. For each category of costs listed in Figure 11.24 (System Costs), Figure 11.26 (Meter Costs), Figure 11.28 (Network Costs), and Figure 11.30 (Program Costs) of Book 2, please indicate those components that will be provided through existing PPL strategic partnerships and those that will be subject to a competitive procurement. In the case where both apply, provide information for a more detailed breakdown of the category. Where strategic partnerships or competitive procurement do not apply, explain how the cost category will be fulfilled, such as internal PPL resources, internal RIE resources, etc.

Response:

Please see the following table that outlines the category of costs and the associated fulfillment approach.

COST CATEGORY	FULFILLMENT APPROACH
Systems	
Headend (1)	Strategic partnership w/ vendor and strategic System Integrator (SI) via Request for Proposal (RFP) bid process
MDMS (1)	Strategic partnership w/ vendor and strategic SI via RFP bid process
Cust Eng	Internal PPL resources and strategic SI via RFP bid process
Analytics (2)	Internal PPL resources and strategic SI via RFP bid process; Strategic partnership w/ vendor for network model analytics
Steady State Ops	Internal PPL resources
Middleware	Internal PPL resources and strategic SI via RFP bid process
ADMS & OMS	Internal PPL resources and strategic SI via RFP bid process
Project Mgmt.	Internal PPL resources
Cyber	Internal PPL resources and strategic SI via RFP bid process
CSS	Internal PPL resources and strategic SI via RFP bid process
Grid Edge Computing	RFP bid process
Deploy Exch. Mgmt.	RFP bid process and strategic SI via RFP bid process

COST CATEGORY	FULLFILLMENT APPROACH
Meter	
Hardware (3)	Strategic partnership w/ vendor
Installs	RFP bid process
Pre-sweeps	RFP bid process
Project Mgmt.	RFP bid process
Repairs	RFP bid process
Network	
Installs (4)	Strategic partnership w/ vendor + internal PPL sourcing
Steady State Ops	Internal PPL resources and strategic partnership w/ vendor
Hardware (3)	Strategic partnership w/ vendor + internal PPL sourcing
Project Mgmt. (4)	Strategic partnership w/ vendor
Program	
Project Mgmt.	RFP bid process and internal RIE and PPL resources
Change Mgmt.	RFP bid process and internal RIE and PPL resources

Specific numbers noted in the table above cross-reference to the numbered categories in Division 4-21.

Please also see the Company's response to Division 4-21 for additional details on these fulfillment approaches.

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

Division 4-21

Request:

For the response to DIV 4-20, in instances where PPL will leverage strategic partnerships, explain how the Company can verify that the most economic vendor solution has been secured if a competitive procurement exercise was not pursued. What specific steps will PPL and RIE take to ensure that existing strategic vendors provide the "best cost" when those vendors have no competition? Does RIE have internal requirements to seek competitive procurement for these components, and if so, how is the Company able to circumvent those requirements?

Response:

Please see the following response that contains the overall background in fulfillment approach followed by additional details by category captured in the Company's response to Division 4-20. The numbered categories below tie back to the cost categories listed in the table provided in the Company's response to Division 4-20.

PPL Electric Utilities Corporation ("PPL Electric") has deployed a full advanced metering functionality ("AMF") solution in Pennsylvania (referred to as advanced metering infrastructure or AMI) and PPL Corporation's ("PPL") regulated utilities in Kentucky are in the process of deploying a full AMF solution with the same AMF vendor. PPL will be leveraging existing system and business processes (tailored for Rhode Island Energy where appropriate) to reduce implementation risk. PPL is familiar with the cost components of an AMF solution. The actual AMF component costs for the Pennsylvania and Kentucky deployments were used as benchmarks for Rhode Island Energy's AMF costs. In addition, the proposed AMF vendor has committed to provide aggregate pricing to Rhode Island Energy that was used in National Grid USA's ("National Grid") prior Rhode Island AMF filing. All strategic partnership solutioning required the proposed AMF vendor to provide a detailed proposal, which was fully evaluated and price negotiated.

The following provides greater detail by cost category on the use of strategic vendors.

(1) Headend and MDMS
For the Systems costs of the Headend and meter data management system ("MDMS"), the proposed AMF vendor provided a written proposal on the scope, capabilities, and costs of the solution. PPL performed a benchmark comparison of the AMF vendor's cloud proposal to the current Pennsylvania Headend and MDMS total costs. PPL used this direct benchmark comparison to negotiate the best price for Rhode Island Energy. PPL also analyzed and leveraged the pricing provided in the Company's previous AMF filing in Docket No. 5113.

(2) Analytics
A small component of the Analytics cost category, and the overall AMF Business Case (0.43%) will be the network model analytics/Advanced Grid Analytics ("AGA"). The AGA was done in Pennsylvania and yielded good results. This cost was validated against the Pennsylvania costs for reasonableness.

(3) Meter and Network Hardware
Along with proving in writing that it would extend aggregate pricing to Rhode Island Energy that was part of the previous Company filing in Docket No. 5113, the planned AMF vendor provided a written proposal with cost estimates and capabilities pertaining to meter and network hardware. PPL used this position as a starting point to negotiate costs associated with the capabilities and channels needed for Rhode Island Energy's AMF proposal. For vendor non-specific AMF hardware, such as cabinets, poles, etc., PPL will procure these items via its Sourcing organization.

(4) Network Installs and Network Installs Project Management
For the network installs and network project management costs, PPL took the following steps to determine a best cost. First, PPL reviewed National Grid's prior installation costs contained in their BCA. Next, PPL had an updated radio frequency ("RF") design analysis performed to align to the capabilities needed. PPL then performed a comparison of the Pennsylvania network install costs to create unit estimates; most importantly the time for a crew to complete installation of various hardware. PPL then took these components to create a bottoms-up view of total costs. The proposed AMF vendor then provided a proposal for network installs and project management. PPL used its bottoms up view, based on experience, to validate the AMF provider proposal. PPL plans to use the same AMF strategic partner to install, configure, and optimize the RF network equipment with which they are the subject matter experts. PPL is leveraging the same approach it successfully executed in Pennsylvania to reduce Rhode Island Energy's AMF implementation risk.

PPL has an overall internal requirement to competitively bid, except for those solution(s) or component(s) meeting the requirements of a sole source justification. In this case the sole source justification is a long-term existing provider who PPL has used successfully, across its other jurisdictions and who has committed to aggregate pricing for Rhode Island Energy that is competitive with the pricing in the Company's prior AMF filing in Docket No. 5113. Also, using technologies provided by a different AMF vendor would not allow the Company to leverage existing system and business processes, and would not align with PPLs enterprise strategy.

As further justification, during higher than usual inflation and amidst global supply chain challenges, PPL was able to leverage an existing partner to a committed implementation cost and delivery timeline.

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

Division 4-22

Response:

How does RIE meter for customers that have DER? Is the metering scheme able to distinguish between customers usage and production or does the metering scheme just record the net of usage and production?

Response:

There are two primary ways that Rhode Island Energy "meters" customers that have distributed energy resources ("DER") depending on the type of customer, size of the DER and the applicable tariff.

Residential customers that have distributed generation ("DG") less than 25 kW use automated meter reading ("AMR") meters that are read monthly with the drive-by system. Residential customers can participate in Net Metering or the Renewable Energy Growth ("RE Growth") program (RE-Growth feed-in tariff), which have different metering requirements. Residential customers participating in Net Metering have one meter that provides a net value (kWh) of the usage and production into the billing system. Residential customers participating in the RE Growth program have two meters measuring production and usage separately.

Commercial customers that have DG greater than 25 kW and who are retail customers use an interval data recorder ("IDR"). The Company accesses the IDR nightly using hard-wired or wireless communications. The IDR provides 5-minute interval data using a MV90 data collection system that can measure bi-directionally. Multiple channels are programmed that typically provide kWh delivered, kWh received, kVAR delivered, and the kVAR received. Stand-alone DG installations get one meter for either Net Metering or REG. Likewise, a behind-the-meter DG installation would have one meter for Net Metering; however, RE Growth program participants have two meters measuring production and usage separately.

Commercial customers that have DG greater than 1MW and who are wholesale customers use an IDR meter, collected via the MV-90 system, as explained above. Multiple channels are programmed that typically provide kWh delivered, kWh received, kVAR delivered, the kVAR received and V^2. A stand-alone DG installation would have one meter for either Net Metering or REG.

Division 4-23

Request:

On page 8 of 20 of the testimony of Briggs and Johnson, it states: "As part of that next base distribution rate case filing, the Company would propose to either: (i) continue with the AMF Factor going forward, or (ii) include future capital and O&M costs for AMF investments (if any) in base distribution rates." Under what conditions would the Company opt for ii) as opposed to i)?

Response:

There are several factors that the Company will consider as part of its next base distribution rate case filing to determine its proposal on the mechanism to recover future advanced metering functionality- ("AMF") -related capital and operations and maintenance ("O&M") costs, including but not limited to (1) the remaining time of AMF deployment at the time of the rate case and (2) the ability to forecast future capital and O&M costs. The further along that the AMF deployment schedule is at the time of a rate case filing and ability to forecast future costs may be conditions under which the Company would opt for (ii). The Company, however, would consider future AMF costs as part of its overall rate case filing and impacts on customers.

Division 4-24

Request:

On AMF BCA Model - Attachment H - FINAL (Confidential), worksheet 2-Cost model & charts – Summary, in Figure 11.22 AMF Cost Summary ($millions) – Electric, how much, if any of the nominal $119.71 million OpEx is proposed to be capitalized?

Response:

Currently, Rhode Island Energy does not anticipate that any of the $119.71 million of forecasted OpEx costs will be capitalized.

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

Division 4-25

Request:

On AMF BCA Attachment H FINAL (Confidential), Worksheet 4-RIE BenCalc please provide an explanation for the assumed Benefit Achievement Rates (BAR) on rows 285 and 286 and why these rows sum to more than 100%?

Response:

This was a calculation error in the spreadsheet. The values in rows 285 and 286 should sum to 100% rather than 109% as they do in the worksheet. Similarly, row 287 should sum to 100% rather than to 9% as it does in the worksheet.

See Attachment DIV 4-25, which shows the original Benefit Achievement Rates and the corrected Benefit Achievement Rates.

AMF Data Request DIV 4-25 Attachment

Original Values - Benefit Achievement Rate

23		**Avoided DSP Sensors**																					SUM
	23a	Feeder monitors - CAPEX %	0%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	109%
	23b	Feeder monitors - OPEX %	0%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	109%
	23c	Feeder monitors - COR %	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	9%

Corrected Values - Benefit Achievement Rate

23		**Avoided DSP Sensors**																					SUM
	23a	Feeder monitors - CAPEX %	0%	10%	9%	9%	9%	9%	9%	9%	9%	9%	9%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	100%
	23b	Feeder monitors - OPEX %	0%	10%	9%	9%	9%	9%	9%	9%	9%	9%	9%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	100%
	23c	Feeder monitors - COR %	0%	10%	9%	9%	9%	9%	9%	9%	9%	9%	9%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	100%

Division 4-26

Request:

On AMF BCA Attachment H FINAL (Confidential), Worksheet 5-Benefit Inputs rows 413 to 428 please provide the details behind the forecasted number of EV's and assumed peak load and energy usage per EV.

Response:

Section 5.3 of the Grid Modernization Plan, filed in Docket No. 22-56-EL contains an electric vehicle ("EV") Forecast section that includes the EV details, at Bates Pages 89-93, which is provided as Attachment DIV 4-26, and describes how the forecasts were derived for 2030, 2040, and 2050. The EV forecast was developed as part of a larger forecast that was designed to meet the Climate Mandates, specifically:

1. 45% CO2 reductions by 2030
2. 80% CO2 reductions by 2040
3. 100% CO2 reductions by 2050.

EVs were determined to be a significant portion of meeting the Climate Mandates and were forecast to increase to 87,300 EVs by 2030; 675,000 by 2040; and 840,000 by 2050. Using these forecast values and a starting estimate of EVs in use today, 4,000-5,000 EVs, the remaining years for the advanced metering functionality ("AMF") benefit-cost analysis ("BCA") analysis were interpolated.

The contribution of each EV to the summer peak and to the winter peak and the energy forecast were developed using the United States ("U.S.") Environmental Protection Agency's ("EPA") Electric Vehicle Infrastructure Projection Tool Lite (the "EVI-Pro-Lite tool"). The EVI-Pro-Lite tool estimates the charging load shape for EVs based on location, number of miles driven, ambient temperature, mix of Level 1 versus Level 2 charging, at home versus at work versus public charging, and the mix of vehicles between Sedans and SUVs.

Specifically, using the 2030 winter peak case, each car contributes approximately 0.9 kilowatts to the peak period after coincidence is considered. Analysis of the 2040 and 2050 data shows that the peak coincident contribution per car increases to 1.35 kilowatts. The energy per car is approximately 4,170 to 4,310 kwh per year. As with the number of EVs, the summer and winter peak contributions and the energy for years other than 2030 and 2040 were interpolated. Starting values were derived from Rhode Island Energy's EV pilot program.

Prepared by or under the supervision of: Wanda Reder

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

Grid Modernization Plan And Attachments

Schedule KC/RC/WR-1

Book 2 of 2

December 30, 2022

RIPUC Docket No. 22-56-EL

5.3 Base Case Development

The existing base case used for the Distribution Study was Rhode Island Energy's three-phase load-flow that was modeled in commercially available CYME software that is used for distribution system planning.[62]

System Topology Update

The topology of the existing Rhode Island Energy sub-transmission and distribution system was modified in the existing base case to represent the upgrades as defined by the current 11 Area Studies such as new or re-conductored sub-transmission or distribution lines, new or upgraded substations/transformers, retirements, etc. This created the future year topology or network configuration as currently planned and is used as the base case for the GMP analysis.

Incorporating Area Study recommendations into the GMP base case was important for two reasons: 1) ensuring that grid modernization infrastructure would not build upon retiring assets nor duplicate planned assets; and 2) ensuring that the Area Study plans would sufficiently support grid modernization needs. These reasons are highlighted by the Providence area investments. The Providence study included recommendations to eliminate certain 4kV substations, such as Geneva and Olneyville, and

[62] *See* https://www.cyme.com/software/

rebuild and expand the Admiral Street substation. Incorporating these changes into the GMP model ensured that the analysis did not utilize infrastructure on Geneva and Olneyville substations or propose new substation infrastructure that was similar electrically to the Admiral Street scope. Furthermore, with the Admiral Street configuration included, the GMP analysis could test whether Admiral Street, or a different near-term scope, should be proposed considering the original area study needs plus the future grid modernization needs.

Study Years

The study years of 2030, 2040, and 2050 were selected to ensure that the long-range effectiveness of the solutions evaluated, did align with the Climate Mandates, i.e., whether the GMP makes sound technical and economic sense now and in the future; and whether any of the currently planned Area Study upgrades need to be modified. The 2050-time frame also coincides with the recent ISO-NE study[63] that was sponsored by the New England Conference of Public Utilities Commissioners ("NECPUC") to evaluate the impacts of the clean energy initiatives to the New England bulk transmission system. Study year cases for the winter, summer, and annual off-peak conditions including 8760-hour load cycles were created for performance analysis, determination of required sub-transmission and distribution upgrades, and evaluation of alternatives. The 8,760-hour load cycle analysis identified the worst peak load demand and worst peak generation operating hours and load conditions that were then modeled on the bulk transmission system for subsequent analysis (see Section 5.9 and 5.10).

Long Range Demand, Energy and Renewable Forecast

The Company's current peak forecast was used as the basis for the GMP forecast.[64] This was done to align with other Company planning efforts and ensure consistency across the Area Studies. Figure 5.3.1 summarizes the forecast details. As can be seen from Figure 5.3.1, the forecast historically considers impacts to peak load. Specifically for 2021, the PV value of 152 megawatts is the reduction on peak for approximately 400 megawatts of nameplate generation. For grid modernization analysis, the focus is no longer on-peak impacts only; therefore, the forecast was adjusted as shown in Figure 5.3.2. Nameplate values and numbers are required instead of peak contributions to provide the necessary inputs to the models. The analysis that determined the number of cars, number of EHPs, and megawatts of solar and wind generation are described below.

[63] ISO-NE 2050 Transmission Study
[64] *See* http://ngrid-ftp.s3.amazonaws.com/RISysDataPortal/Docs/RI_PEAK_2022_Report.pdf

Figure 5.3.1: Rhode Island Energy Peak Forecast

NECO	SUMMER 50/50 Peaks (MW) (before & after DERs)								
	SYSTEM PEAK		DER IMPACTS						
Calendar Year	Reconstituted Load MW PreDER	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2021	2,260	**1,729**	(350)	(152)	1.6	(29.1)	(0.9)	(1.4)	(531)
2022	2,192	**1,738**	(370)	(50)	3.9	(33.4)	(1.3)	(2.5)	(453)
2023	2,231	**1,745**	(387)	(62)	6.1	(38.4)	(1.7)	(3.8)	(486)
2024	2,264	**1,746**	(404)	(73)	9.2	(42.4)	(2.1)	(5.3)	(518)
2025	2,299	**1,751**	(422)	(84)	13.3	(44.3)	(2.6)	(7.2)	(547)
2026	2,319	**1,746**	(440)	(95)	18.8	(44.3)	(3.0)	(9.3)	(573)
2027	2,260	**1,761**	(458)	(13)	30.2	(44.3)	(3.4)	(10.8)	(499)
2028	2,287	**1,777**	(475)	(14)	40.7	(44.3)	(3.8)	(13.6)	(510)
2029	2,312	**1,793**	(491)	(15)	53.8	(44.3)	(4.2)	(17.1)	(518)
2030	2,335	**1,812**	(507)	(16)	69.6	(44.3)	(4.7)	(21.2)	(523)
2031	2,355	**1,830**	(522)	(16)	88.2	(44.3)	(5.1)	(25.5)	(525)
2032	2,373	**1,851**	(536)	(17)	109.6	(44.3)	(5.5)	(29.5)	(523)
2033	2,389	**1,872**	(549)	(18)	133.5	(44.3)	(5.9)	(33.4)	(517)
2034	2,400	**1,891**	(562)	(18)	159.5	(44.3)	(6.3)	(37.1)	(509)
2035	2,399	**1,902**	(574)	(19)	187.6	(44.3)	(6.7)	(40.6)	(497)
2036	2,411	**1,928**	(586)	(19)	217.4	(44.3)	(7.1)	(43.9)	(483)

Figure 5.3.2: GMP Forecast[65]

GMP DER Forecast/Impact to Peak						
	2030		2040		2050	
	Summer	Winter	Summer	Winter	Summer	Winter
Heat Pumps (Ea.) Forecast	54,000	54,000	325,000	325,000	400,000	400,000
Heat Pumps (MW) @ Peak	0	200	5	1310	5	2825
Solar PV Nameplate (MW) Forecast	1,500	1,500	3,400	3,400	5,000	5,000
Solar PV Nameplate (MW) @ Peak	0	0	0	0	0	0
Electric Vehicles (Ea.) Forecast	87,300	87,300	675,000	675,000	840,000	840,000
Electric Vehicles (MW) @ Peak	70	80	805	910	1010	238
RIE Peak Demand (MW)	**1,940**	**1,415**	**2,519**	**3,280**	**2,785**	**3,855**

More Distributed Generation than Load

Winter Peak

Peak Demand Doubles

As can be seen in Figure 5.3.2, the combined impact of electric heating and EV conversion will double the Rhode Island Energy peak demand by 2050. The 2021 summer peak demand was 1,800 MW and is projected to increase to 1,940 MW by 2030; 2,519 MW by 2040; and 2,785 by 2050. The winter peak demand was 1,180 MW in the winter of 2020/21. The winter peak is forecasted to increase to 1,415 MW by 2030 and 3,280 MW by 2040. The Rhode Island Energy system is forecasted to switch from being summer peaking to being winter peaking in 2034, driven predominantly by heating load electrification.

The numbers and megawatts of DER resources were developed using emissions data from the 2019 EIA report for Rhode Island assuming the State's Climate Mandates will be achieved through adoption of a combination of solar generation, wind energy production, EV, and EHP conversion. Figure 5.3.3 shows the EIA data in million metric tons of CO_2 per sector.

The Climate Mandates emission goals are:

1. 45% CO_2 reductions by 2030
2. 80% CO_2 reductions by 2040

[65] ISO-NE forecast 59,300 RI homes with heat pumps by 2031 aligned with GMP forecast of 60,000. *See* https://www.iso-ne.com/static-assets/documents/2022/04/final_2022_heat_elec_forecast.pdf

3. Net zero (100%) CO2 reductions by 2050

Figure 5.3.3: EIA Data – Million Metric Tons of CO2 Per Sector

Rhode Island Carbon Dioxide Emissions from Fossil Fuel Consumption (2019)		2019 million metric tons CO2
Residential Sector		
	Coal	0.00
	Petroleum Products	0.98
	Natural Gas	1.08
	Total	2.06
Commercial Sector		
	Coal	0.00
	Petroleum Products	0.26
	Natural Gas	0.68
	Total	0.94
Industrial Sector		
	Coal	0.00
	Petroleum Products	0.17
	Natural Gas	0.46
	Total	0.63
Transportation Sector		
	Coal	0.00
	Petroleum Products	3.79
	Natural Gas	0.14
	Total	3.93
Electric Power Sector		
	Coal	0.00
	Petroleum Products	0.01
	Natural Gas	2.81
	Total	2.81
	Grand Total	**10.37**

To determine the electric distribution system impacts, the CO2 values were converted to British Thermal Units (BTUs) and then to megawatt*hours. First, the percent of each sector that could be converted was determined. For example, the space heating portion of the petroleum based Residential Sector was considered to be 81%. Next, end-use efficiency was applied to determine the value of energy actually used. This end use energy was shifted to the electric sector based on approximation of the Climate Mandates targets. To find the new electric sector generation needs, the efficiency of the electric technology was applied. Finally, renewable generation was added and adjusted to achieve emission goals.

Example calculation – 2019 EIA Residential – Petroleum related CO_2 = 0.98 million metric tons

1. Convert to Trillion BTU = 13.4
2. Apply % of sector associated with space heating – 81% *13.4 = 10.9

   CO2 shifting opportunity

3. Apply end use efficiency to find end use energy actually used
   a. Oil boiler considered 84% efficient – 84% * 10.9 = 9.16
4. Convert to end use trillion BTUs to MWh – 2,685,000

   Energy actually used for end use

5. Shift to Electric Sector based on climate goals
   a. 2030 Shift – 20% -> 537,000 MWh
   b. 2040 Shift – 80% -> 2,148,000 MWh
   c. 2050 Shift - 100% -> 2,685,000 MWh
6. Apply electric technology efficiency to find generation need
   a. EHP average coefficient of performance – 2.98 or 298%
   b. Electric system losses – 6%
   c. Effective efficiency – 298%*94% = 280%
   d. Generation needs to supply:
      i. 2030 -> 192,000 MWh
      ii. 2040 -> 766,000 MWh
      iii. 2050 -> 958,000 MWh
7. Determine renewable allocation of generation need

   Generation need is less than energy need as a result of heat pump efficiency

   a. If all served by solar (17% AC capacity factor):
      i. 2030 -> 130 MW
      ii. 2040 -> 515 MW
      iii. 2050 -> 645 MW
   b. If all served by off-shore wind (43% AC capacity factor):
      i. 2030 -> 50 MW
      ii. 2040 -> 205 MW
      iii. 2050 -> 255 MW
   c. Establish balance between solar, onshore wind, and offshore wind generation

The results of the emission conversion are shown in Figure 5.3.4

Figure 5.3.4: Emission Conversion to Electric Sector

Sector	Sector Detail	Sector Opportunity	2030 % Transferred	2040 % Transferred	2050 % Transferred
Transportation	EVs-Light Duty	86%	10%	80%	100%
Transportation	EVs-Heavy Duty	86%	5%	80%	100%
Residential	EHP-Oil	81%	20%	80%	100%
Residential	EHP-Natural Gas	71%	5%	80%	100%
Commercial	EHP-Oil	63%	20%	80%	100%
Commercial	EHP-Natural Gas	73%	5%	80%	100%
Industrial	EHP-Oil	3%	20%	80%	100%
Industrial	EHP-Natural Gas	12%	5%	80%	100%
Electric Power	Wind MW		1000	1150	1450
Electric Power	Solar MW		1,500	3,400	5,000

The resulting projected carbon dioxide emissions are shown in Figure 5.3.5.

Figure 5.3.5: Resulting Million Metric Tons of CO2 By Sector

Rhode Island Carbon Dioxide Emissions from Fossil Fuel Consumption		2030 million metric tons CO2	2040 million metric tons CO2	2050 million metric tons CO2
Residential Sector				
	Coal	0	0	0
	Petroleum Products	0.82	0.34	0.18
	Natural Gas	1.05	0.47	0.32
	Total	1.87	0.81	0.50
Commercial Sector				
	Coal	0.00	0.00	0.00
	Petroleum Products	0.23	0.13	0.10
	Natural Gas	0.65	0.28	0.18
	Total	0.88	0.41	0.28
Industrial Sector				
	Coal	0.00	0.00	0.00
	Petroleum Products	0.17	0.16	0.16
	Natural Gas	0.46	0.42	0.40
	Total	0.62	0.58	0.57
Transportation Sector				
	Coal	0.00	0.00	0.00
	Petroleum Products	3.40	1.15	0.52
	Natural Gas	0.14	0.14	0.14
	Total	3.53	1.29	0.65
Electric Power Sector				
	Coal	0.00	0.00	0.00
	Petroleum Products	0.00	0.00	0.00
	Natural Gas	0.76	1.19	0.35
	Total	0.76	1.19	0.35
	Grand Total	**7.67**	**4.28**	**2.35**
Percent Reduction of CO2 Opportunity		45%	80%	100%

EV Forecast

Today there are between 4,000 and 5,000 EVs operating in the state of Rhode Island.[66] This is projected to increase to 87,300 EVs by 2030; 675,000 by 2040; and 840,000 by 2050. With this forecast, most light trucks and automobiles would have been switched to electric by 2050. This assumption is a key component of the Climate Mandates requiring reduced carbon emissions.

In 2022, approximately 42% of EVs use Level 1 chargers and 58% utilize Level 2 chargers. This is projected to decrease to 20% Level 1 and increase to 80% Level 2 by 2050. The increase in Level 2 charging will be required through advances in technology driven by the need for consumers to have sufficient energy storage/driving capability to meet projected daily driving requirements. The combined impact of the increase in the number of EVs and the increase in Level 2 charging can add over 700 MW to the summer peak demand and over 1,000 MW to the winter peak demand by 2050. Over 3,600 Gwh in annual energy growth can be added to the Rhode Island Energy electric system by 2050.

To develop the EV load cycle, the U.S Department of Energy's EVI-Pro Lite tool was used.[67] EVI-Pro Lite was created to assist planning organizations to estimate how much EV charging a city or state might need to meet their goals. The model considers travel patterns, charging station details, and EV details. A significant benefit of this tool is a weekday and weekend load cycle application which provides the needed details for this GMP analysis. Load cycle inputs for the three test years are shown in Figure 5.3.6. Summer, winter and spring/fall load cycles were developed and repeated for the respective season to create an 8760-hour yearly load cycle. Figures 5.3.7 through 5.3.9 show the 2030 weekday/weekend load cycles for each season, which demonstrate how the hourly energy of the various charging methods add to create an overall stacked line EV curve.

[66] *See* https://www.dot.ri.gov/projects/EVCharging/#:~:text=There%20are%20about%20300%20charging%20stations%20already%20in%20the%20state,electric%20vehicles%20in%20Rhode%20Island.AMF Testimony List of Information and Data needed
[67] *See* https://afdc.energy.gov/evi-pro-lite

Figure 5.3.6: EVI-Pro Lite Inputs

Input	2030	2040	2050
Number of EVs	87300	675,000	840,000
Average daily miles traveled[68]	25	25	25
Average ambient temperature	Winter – 14degF Spring/Fall – 50degF Summer – 86degF	Winter – 14degF Spring/Fall – 50degF Summer – 86degF	Winter – 14degF Spring/Fall – 50degF Summer – 86degF
Percent vehicles that are all-electric	EV Dominant	EV Dominant	EV Dominant
Percent vehicles that are sedans	80% Sedans / 20% SUVs	80% Sedans / 20% SUVs	80% Sedans / 20% SUVs
Percent mix of workplace charging	50% Level 1 and Level 2 charging	20% Level 1 and 80% Level 2 charging	20% Level 1 and 80% Level 2 charging
Percent access to home charging	75% access	100% access	100% access
Percent mix of home charging	80% Level 1 and 20% Level 2 charging	20% Level 1 and 80% Level 2 charging	20% Level 1 and 80% Level 2 charging
Percent preference to home charging	100%	100%	100%
Home charging strategy	As fast as possible	As fast as possible	As fast as possible
Workplace charging strategy	As fast as possible	As fast as possible	As fast as possible

[68] Current Rhode Island information indicates daily miles driven are approximately 30 miles per day. However, daily miles are anticipated to decrease over time. 25 miles per day is the lowest setting.

Figure 5.3.7: 2030 Summer – Weekday and Weekend Load Cycle (Stacked Line)

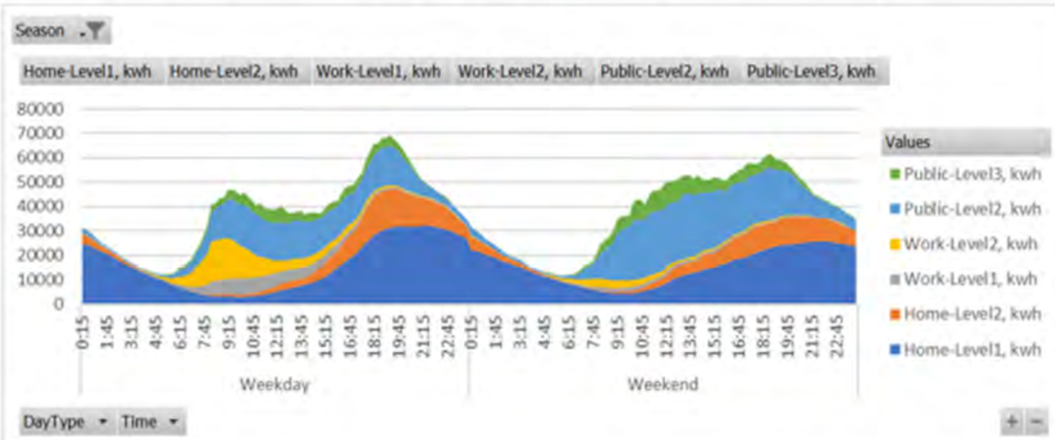


Figure 5.3.8: 2030 Spring/Fall – Weekday and Weekend Load Cycle (Stacked Line)

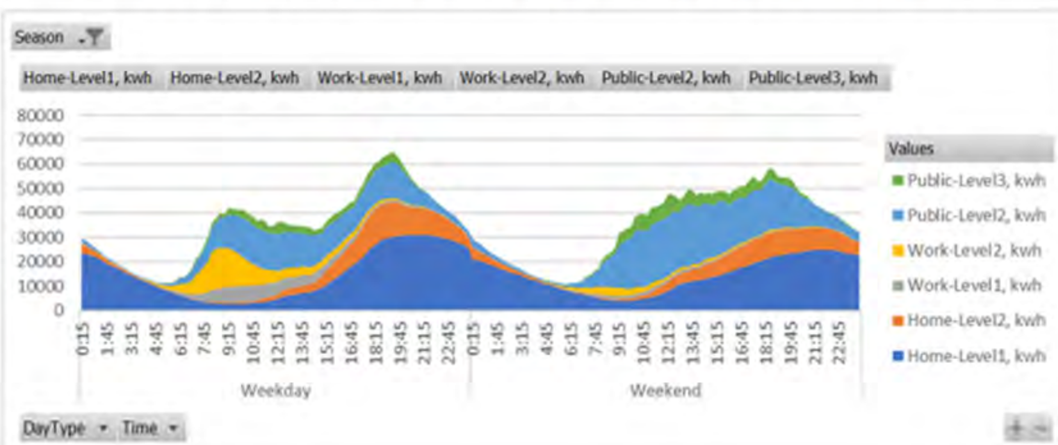
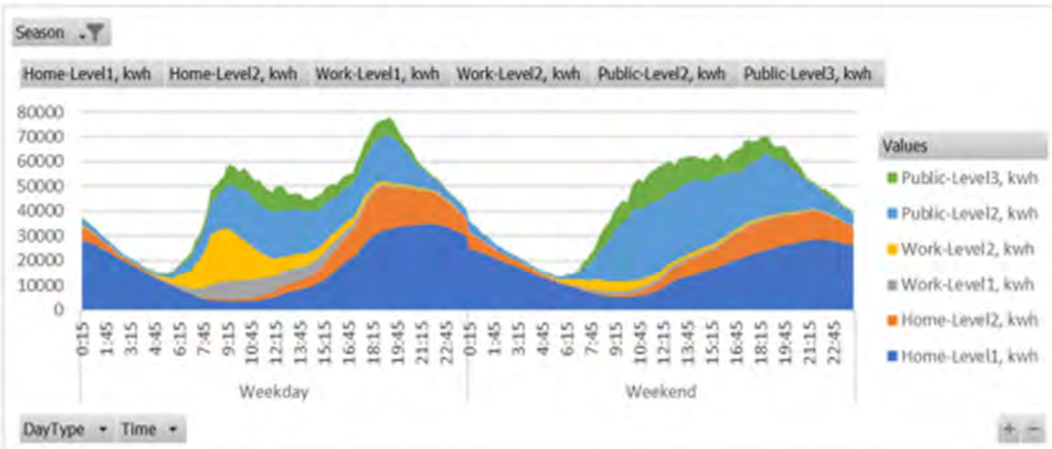
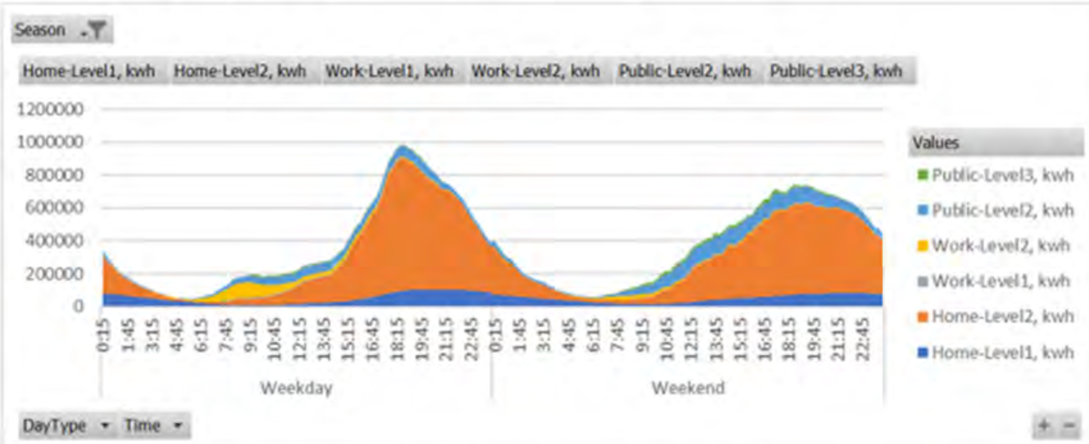


Figure 5.3.9: 2030 Winter – Weekday and Weekend Load Cycle



As can be seen from Figure 5.3.7 through 5.3.9, the ambient temperature affects battery performance increasing energy requirements during the summer and winter. The spring weekday peak is approximately 65,000 kilowatts, while the summer and winter weekday peaks are 70,000, and 79,000 kilowatts respectively. Using the 2030 winter peak as the worst case, each car contributes approximately 0.9 kilowatts to the peak period. Analysis of the 2040 and 2050 data shows that the peak contribution per car increase to 1.35 kilowatts for 2040 and 2050. Further, the charging behavior, set to "as fast as possible," results in a peak impact that coincides with the typical distribution circuit evening peak. Regardless of peak impacts, the 2030 charging schedule shows substantial energy usage aligned with solar generation hours. That alignment with generation diminishes as the number of EVs increase and charging power increases as shown in Figure 5.3.10.

Figure 5.3.10: 2050 Summer – Weekday and Weekend Load Cycle



The figure above represents approximately 840,000 vehicles in 2050. Home and workplace level 1 charging becomes minor. Although there is still some daytime energy that aligns with solar generation, the far magnitude of the energy is in the evening hours.

EV Charging Forecast Allocation to Network Model

To allocate the EV charging forecast to the distribution network for the 2030/40/50 study years, the approach used was to allocate EV vehicles to existing customer load points which represent residences within the CYME model. By 2030 it was assumed that 22% of residences would have one EV. By 2040, all residences are assumed to have one EV, with approximately 70% having 2 EVs. By 2050 it was assumed that 100% of the residences would have two EVs. By placing the EVs at existing customer sites, the best possible distribution is obtained aligned with home charging expectations. Furthermore, this method enabled the use of CYME application functionality to directly assign load cycle information to the modeled EV load.

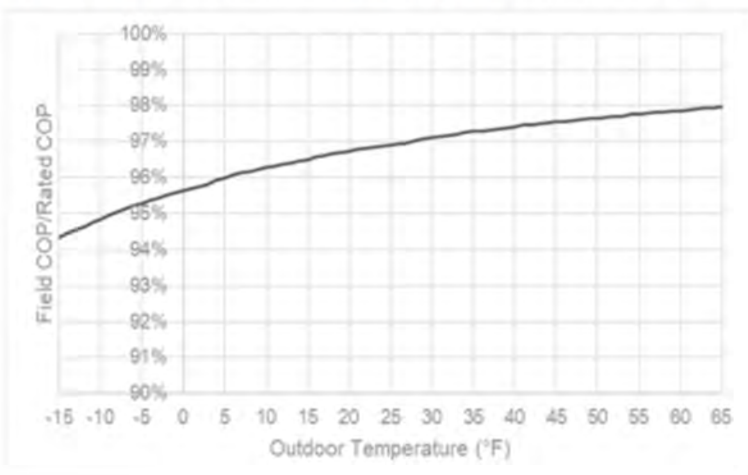
Electric Heat Pump Forecast

There are 4,000 to 6,000 homes heated with EHPs today while there are approximately 400,000 businesses and residences heating with gas/oil fuel. The number of homes/businesses converting from gas/oil to efficient EHPs for heating and air conditioning is projected to increase to 51,000 by 2030; 325,000 by 2040; and 400,000 by 2050.

The impact of this conversion will add significant peak demand and annual energy requirements to the Rhode Island Energy electrical distribution systems. It will also shift the annual peak demand on the system in a manner that will make the winter peak the highest peak demand of the year. Based on this conversion, the winter peak demand will increase by 220 MW in 2030; 1,310 by 2040 MW; and 2,825 MW by 2050. The EHP impact on the summer peak demand is projected to be trivial. This is because EHPs are expected to replace existing air conditioners, where the load increase is only the efficiency difference between the EHPs and older equipment. The overall conversion is expected to increase the annual energy requirements for Rhode Island by 2,200 Gwh.

To develop the EHP load cycle, a custom-built model was developed. The model uses a 2015 temperature cycle as an extreme winter peak case with average heating energy. Inputs include daytime and nighttime turn on temperatures, backup heating assumptions (resistive heat), improvements in building efficiency, and adjustable coefficient of performance ("COP") based on ambient temperature. Figure 5.3.11 shows the impact of temperature on the COP.

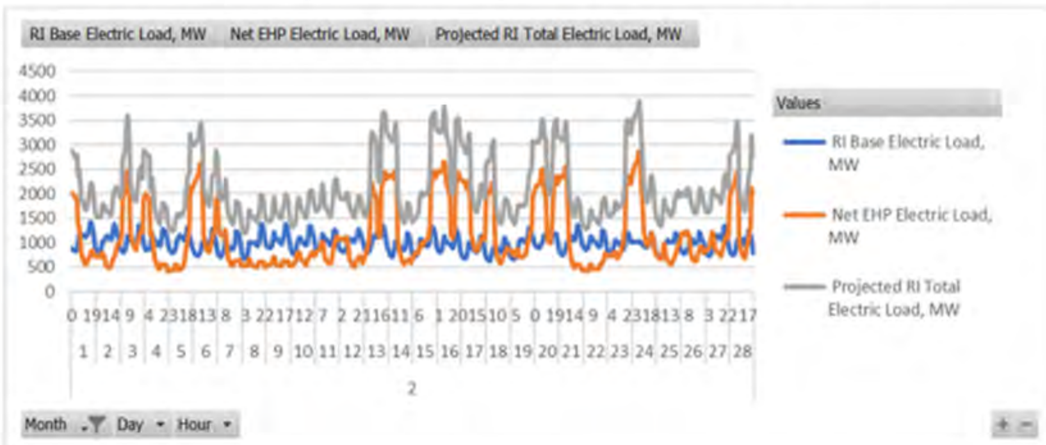
Figure 5.3.11: Impact of Temperature on Heat Pump Coefficient of Performance[69]



[69] *See* https://ma-eeac.org/wp-content/uploads/MA19R16-B-EO_Energy-Optimization-Measures-and-Assumptions-Update-Memo_Final_2020-03-02-1.pdf

Figure 5.3.12 shows the month of February, as an example, demonstrating the resulting EHP load cycle (orange line) and its resulting impact to total Rhode Island load (gray line). As can be seen from the graph, heating loading can result in a peak over 3700 megawatts for Rhode Island. The increased loads are driven by the coldest days, which include substantial resistive heat that occurs early morning and late evening when thermostat adjustments are typically made.

Figure 5.3.12: Impact of Temperature on Heat Pump Coefficient of Performance



Electric Heat Pump Forecast Allocation to Network Model

To allocate the EHP forecast to the distribution network for the 2030/40/50 study years, the approach used was to allocate the addition EHP demand to each customer residence. By 2030 approximately 13% of the Rhode Island homes can be converted to EHPs, increasing to 80 percent in 2040, and to 100 percent by 2050. By placing the EHPs at existing customer sites, the best possible distribution is obtained and aligned with home heating expectations. Furthermore, this method enabled the use of CYME application functionality to directly assign load cycle information directly to the modeled EHP load.

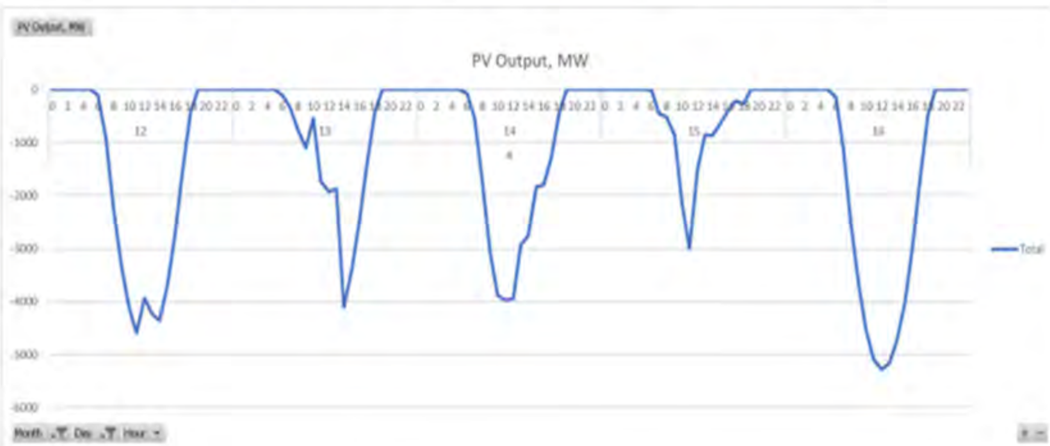
It is significant to note that the amount of solar PV forecast to meet the Climate Mandates by 2050 is 5,000 MW nameplate capacity, which exceeds the expected peak demand during the summer peak – 2,785 MW in 2050. In addition, the winter peak demand in 2050 is essentially double what it is today because of the demand increases created by the EHP load and EV charging. This will double the loading on the T/D system requiring significant upgrades to meet the load and keep the lights on.

Solar PV Forecast

Today there is about 504 MW (DC nameplate capacity) of solar PV connected to the Rhode Island Energy electric distribution system and over 600 MW in the interconnection queue. This existing PV provides an annual energy supply to Rhode Island of approximately 618,000 MWh. To meet the state's Climate Mandates, the PV nameplate capacity in the Distribution Study was forecasted to be a total of 1,800 MW by 2030; 3,700 MW by 2040; and 5,300 MW by 2050.

The National Renewable Energy Lab's ("NREL") PVWatts Calculator[70] was used to develop the solar generation cycle. This online calculator uses solar radiation data to estimate hour-by-hour PV data. The resulting generation cycle provides suitable test points that represent full solar output and potentially cloud covered periods as shown in Figure 5.3.13.

Figure 5.3.13: Example 5 Day Sample - PVWatts Generation Cycle



Solar PV Allocation to Network Model

To allocate the forecasted Solar PV to the distribution network for the 2030/40/50 study years, the total solar generation determined by the emission analysis was assigned to the distribution feeder based upon its load. In other words, the generation was allocated to the load as closely as possible. In this manner, the analysis is not influenced by large locational differences between generation and load that could

[70] *See* https://pvwatts.nrel.gov/

skew infrastructure requirements. Instead, as intended, the analysis could focus on the time disparity between the generation and load cycles. Once the generation was allocated by feeder, it was spread randomly across the circuit topology in relatively small sizes. This ensured the analysis and infrastructure requirements were not influenced by large clusters of generation. Although this contrasts with the real-world conditions where large DER sites are interconnected, this allocation method was chosen to be conservative in nature, representing a best-case outcome.

It is significant to note that the amount of solar PV forecast to meet the Climate Mandates by 2050 is 5,000 MW nameplate capacity, which exceeds the expected peak demand during the summer peak in 2050.

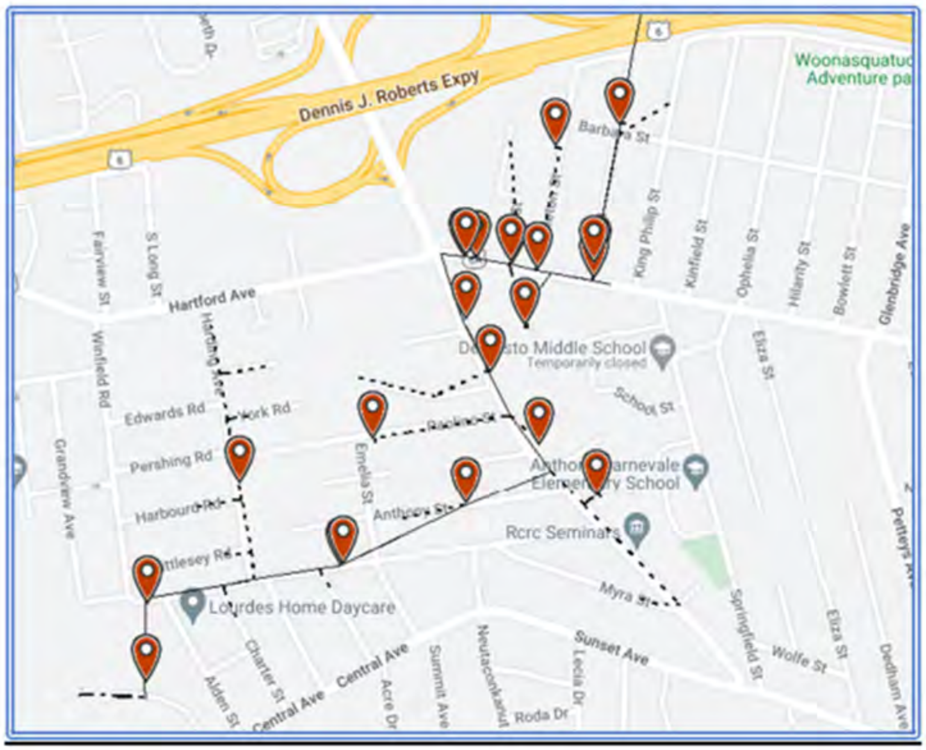
Figure 5.3.14 provides an example of the PV allocation by feeder. This example also illustrates a manual allocation of some PV to the supply line. Although the supply lines may not serve load directly, they typically have relatively high capacity that may be suitable for generation interconnection as demonstrated by recent interconnection applications. This manual effort was designed to make maximum use of that capacity.

Figure 5.3.14: Example PV Allocation – Johnston Substation

Substation	Feeder or Supply Line	Allocated MW PV 2030	Allocated MW PV 2040	Allocated MW PV 2050	2040 Manual DG Allocation	2050 Manual DG Allocation
JOHNSTON	18F10	3.66	8.42	12.43	-	-
JOHNSTON	18F11	0.00	3.66	7.47	-	-
JOHNSTON	18F12	1.53	3.48	5.11	-	-
JOHNSTON	18F13	3.22	7.49	11.09	-	-
JOHNSTON	18F14	1.62	3.68	5.42	-	-
JOHNSTON	18F5	3.47	8.50	12.73	-	-
JOHNSTON	18F6	0.00	1.81	5.06	-	-
JOHNSTON	18F7	3.06	7.45	11.16	-	-
JOHNSTON	18F8	1.83	5.09	7.84	-	-
JOHNSTON	18F9	3.49	8.37	12.47	-	-
JOHNSTON	2202	0.00	0.00	0.00	-	-
JOHNSTON	2211	10.26	23.25	34.19	2.00	10.00
JOHNSTON	2226	0.00	0.00	0.00	-	-
JOHNSTON	2227	7.78	17.64	25.94	2.00	10.00
JOHNSTON	2228	5.35	12.13	17.83	2.00	10.00

Figure 5.3.15 illustrates the distributed method to allocate the generation within the model.

Figure 5.3.15: Example Model Distribution of PV – Portion of 18F5 Feeder

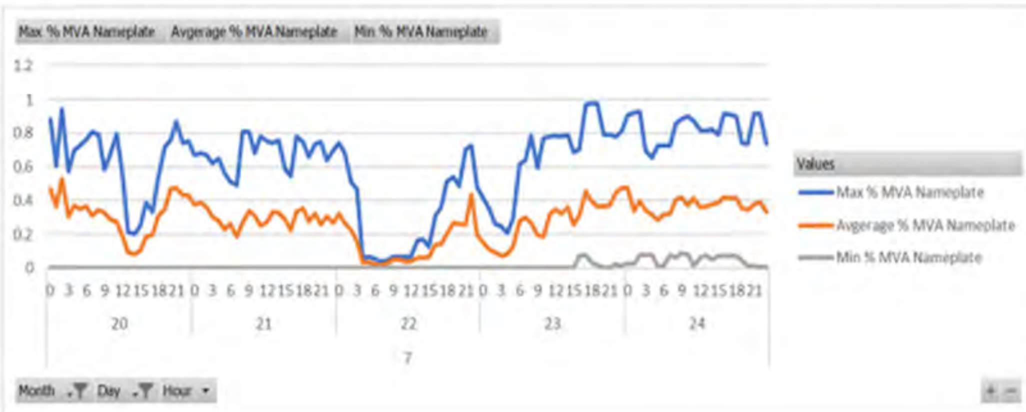


Wind Forecast

Today there is approximately 50 MW of onshore wind and 30 MW of offshore wind in Rhode Island. There is an offshore wind farm pending interconnection with 400 MW allocated to Rhode Island. The existing wind generation provides an annual energy supply to Rhode Island of approximately 165,000 MWh. To meet the State's Climate Mandates, the onshore and offshore wind will need to respectively increase to 100/900 MW by 2030; 115/1,035 MW by 2040; and 145/1,300 MW by 2050.

The wind generation cycle was developed using existing data. The resulting generation cycle results in substantial variability as shown in Figure 5.3.16. The figure shows the maximum, minimum, and average across a sample 5-day period which includes the typical summer peak day. It is preferable to have the minimum and maximum line as close as possible, which would indicate a dependable source. In this case, the graph shows that for most hours, the generation output ranges between 0 and nameplate rating.

Figure 5.3.16: Example 5 Day Sample - Wind Generation Cycle



Wind Allocation to Network Model

The forecasted onshore wind generation was manually added to the distribution supply lines. This was done because of the relatively small onshore wind volume as compared to solar generation and the higher capacity of the supply lines. The offshore wind generation was included in the transmission model.

Design and Performance Criteria

The studies were conducted following approved Rhode Island Energy sub-transmission and distribution planning procedures. Design for upgrades and new facilities followed best practices for feeder design, transformer sizing, substation design, etc. The performance criteria used was based on identifying thermal and voltage violations on the electric system:

1. Voltages below 95% or above 105% of nominal voltage
2. Thermal loading on equipment exceeding its ratings