The Narragansett Electric Company
d/b/a National Grid

Updated Advanced Metering Functionality Business Case

Testimony and Attachments of:
Kristoffer P. Kiefer &
Stephen Lasher

Book 1 of 3

January 21, 2021

RIPUC Docket No. 5113

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

Filing Letter & Motion

nationalgrid

Jennifer Brooks Hutchinson
Senior Counsel

January 21, 2021

VIA HAND DELIVERY AND ELECTRONIC MAIL

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

RE: Docket No. 5113 - The Narragansett Electric Company d/b/a National Grid
Updated Advanced Metering Functionality Business Case

Dear Ms. Massaro:

Enclosed for filing with the Public Utilities Commission (PUC) is an original and ten copies of the Company's[1] Updated Advanced Metering Functionality (AMF) Business Case pursuant to Article II, Section C.16.a of the Amended Settlement Agreement (ASA) approved by the PUC at its Open Meeting on August 24, 2018 in Docket Nos. 4770 & 4780.[2]

The Company's filing consists of a detailed proposal to implement AMF, also known as smart metering, across its service territory.[3] The proposal, which is being filed concurrently with the Company's Grid Modernization Plan (GMP), will enable significant customer and grid benefits in line with shared clean energy goals. If approved, the program is estimated to cost $224 million on a net present value (NPV) basis and provide benefits of $533 million (NPV) over the 20-year project life. As explained in more detail in the Updated AMF Business Case, the Company's AMF proposal is intended to address three key unmet needs in Rhode Island: (1) evolving customer expectations; (2) replacement of existing automated meter reading meters, which are nearing the end of their useful life and have limited functionality; and (3) taking further steps to achieve clean energy goals. The Company's proposal represents a once-in-a-generation opportunity to deploy this new technology and empower customers to take control of their energy usage.

The Company has undertaken a thoughtful and thorough approach to developing the Updated AMF Business Case and is pleased to submit this proposal to the PUC for review and approval. This process, which spanned approximately two years, included engagement with stakeholders through the AMF/GMP Subcommittee of the Power Sector Transformation Advisory Group, as well as other targeted deep-dive sessions with the Division of Public Utilities and Carriers and the Office of Energy Resources, and a workshop and two additional technical sessions with the PUC. The Company has worked to incorporate stakeholder and PUC feedback into the Updated AMF Business Case (and the concurrently filed GMP) to address each of the

[1] The Narragansett Electric Company d/b/a National Grid (the Company).
[2] *See* Docket Nos. 4770 & 4780, Report and Order No. 23823 (May 5, 2020).
[3] This equates to approximately 525,000 electric meters and 277,000 gas modules.

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AMF requirements as set forth in the ASA. A summary of the collaboration schedule and stakeholder feedback is more fully described in Section 2.1 of the Updated AMF Business Case.

The Company's filing also includes a request for approval to adjust base distribution rates effective September 1, 2021, to recover the incremental electric and gas revenue requirements associated with the implementation of the Company's proposed AMF investments and related expenses as provided in Article II, Section C.16.c of the ASA. As described in the pre-filed joint direct testimony of the Revenue Requirements and Pricing Panel, the AMF revenue requirements result in an increase of $6.2 million for the Company's electric operations and $1.8 million for the Company's gas operations, above the most recently approved Rate Year 3 (i.e. September 1, 2020 through August 31, 2021) revenue requirements in Docket No. 4770. These revenue requirements reflect costs the Company is proposing to recover over a 12-month period beginning with Rate Year 4 (i.e., September 1, 2021). In addition, the Company is proposing an incentive structure that guarantees 80 percent of the Non-Outage Management System Avoided Operations and Maintenance Costs benefits to customers in the first rate period following AMF approval.

In Rate Year 4, the monthly bill impact for a residential electric customer on Last Resort Service (which was previously known as Standard Offer Service prior to January 1, 2021) and using 500 kWh per month is $0.60 or 0.5%. The annual bill impacts for a residential gas heating customer using 845 therms per year is $5.25 or 0.4%.

Enclosed are three (3) books containing the Company's AMF proposal and supporting materials as follows:

<u>Book 1</u>

- Joint Direct Testimony of Kristoffer P. Kiefer and Stephen Lasher in support of the Company's Updated AMF Business Case; and
- Schedule KPK/SL-1 - Updated AMF Business Case and Appendices.

<u>Book 2</u>

- Customer Engagement Plan (Attachment A);
- Data Governance and Management Plan (Attachment B);
- Time Varying Rates Overview (Attachment C);
- Metrics and Performance Incentive Measures Roadmap (Attachment D); and
- Benefit-Cost Analysis – **CONFIDENTIAL** (Attachment E).

Book 3

- Joint Testimony and schedules of the Revenue Requirements and Pricing Panel, consisting of Melissa A. Little, Director for New England Revenue Requirements; Adam S. Crary, Lead Analyst in the New England Electric Pricing group; and Michael M. Pini, Lead Program Manager in the New England Pricing group, presenting the increase in electric and gas revenue requirements, together with the proposed base distribution rates effective September 1, 2021 and the associated bill impacts.

This filing also includes a Motion for Protective Treatment in accordance with Rule 1.3(H)(3) of the PUC's Rules of Practice and Procedure, 810-RICR-00-00-1-1.3(H)(3) and R.I. Gen. Laws § 38-2-2(4)(B). The Company seeks protection from public disclosure of the confidential Benefit-Cost Analysis in Attachment E (Book 2). Due to the size and voluminous nature of the Excel file, the Company is providing the PUC with the confidential Excel file via the PUC's secure website and marked as **"Contains Privileged and Confidential Information – Do Not Release."** Accordingly, the Company has not included redacted copies of this material for the public filing.

Thank you very much for your time and attention to this matter. If you have any questions, please contact Jennifer Brooks Hutchinson at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosures

cc: John Bell, Division
Leo Wold, Esq.

STATE OF RHODE ISLAND

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Updated Advanced Meter Functionality Business Case	)	Docket No. 5113

MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] hereby respectfully requests that the Rhode Island Public Utilities Commission (PUC) provide confidential treatment and grant protection from public disclosure of certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by Rule 1.3(H)(3) of the PUC Rules of Practice and Procedure, 810-RICR-00-00-1-1.3(H)(3) (Rule 1.3(H)), and R.I. Gen. Laws § 38-2-2(4)(B). National Grid also hereby requests that, pending entry of that ruling, the PUC preliminarily grant National Grid's request for confidential treatment pursuant to Rule 1.3(H)(2).

I. BACKGROUND

On January 21, 2021, National Grid submitted its Updated Advanced Meter Functionality Business Case in the above-captioned docket. In that filing, the Company filed its BCA Model in Excel format as Attachment E to the Pre-filed Joint Direct Testimony of Kristoffer P. Kiefer and Stephen Lasher (the BCA Model). The BCA Model contains confidential and proprietary commercial and financial information that the Company ordinarily would not share with the public.

Therefore, the Company requests that, pursuant to Rule 1.3(H), the PUC afford confidential treatment to the BCA Model.

II. LEGAL STANDARD

Rule 1.3(H) provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1, *et seq.* APRA establishes the balance between "public access to public records" and protection "from disclosure [of] information about particular individuals maintained in the files of public bodies when disclosure would constitute an unwarranted invasion of personal privacy." Gen. Laws § 38-2-1. Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency are deemed "public records" unless the information contained in such documents and materials falls within one of the exceptions specifically identified in Gen. Laws § 38-2-2(4). *See id.* § 38-2-3. To the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of APRA to deem such information as confidential and to protect that information from public disclosure.

APRA provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation that is of a privileged or confidential nature.

Id. § 38-2-2(4)(B).

The Rhode Island Supreme Court has held that when documents fall within a specific APRA exemption, they "are not considered to be public records," and "the act does not apply to them." *Providence Journal Co. v. Kane*, 577 A.2d 661, 663 (R.I. 1990). Further, the court has

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

held that "financial or commercial information" under APRA includes information "whose disclosure would be likely either (1) to impair the Government's ability to obtain necessary information in the future, or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained." *Providence Journal Co. v. Convention Ctr. Auth.*, 774 A.2d 40, 47 (R.I. 2001) (internal quotation marks omitted). The first prong of the test is satisfied when information is voluntarily provided to the governmental agency, and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. *Id.* at 47.

III. BASIS FOR CONFIDENTIALITY

The BCA Model contains confidential and proprietary commercial and financial information relating to the Company's business operations. The Company ordinarily does not make it available to the public. The Company has provided it on a voluntary basis to assist the PUC with its decision-making in this proceeding. Therefore, this information satisfies the APRA exception found in Gen. Laws § 38-2-2(4)(B).

The BCA Model constitutes "commercial or financial information" to which the APRA public disclosure requirements do not apply. *See* Gen. Laws § 38-2-2(4)(B); *Kane*, 577 A.2d at 663. The Company therefore respectfully requests that the PUC grant protective treatment to the BCA Model and take the following actions to preserve its confidentiality: (1) maintain the BCA Model as confidential indefinitely; (2) not place the BCA Model on the public docket; and (3) disclose BCA Model only to the PUC, its attorneys, and staff as necessary to review this docket.

IV. CONCLUSION

For the foregoing reasons, National Grid respectfully requests that the PUC grant its Motion for Protective Treatment of Confidential Information.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID

By its attorney,

____
Jennifer Brooks Hutchinson, Esq. (#6176)
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-7288
Dated: January 21, 2021

Joint Testimony of
Keifer & Lasher

JOINT PRE-FILED TESTIMONY

OF

KRISTOFFER P. KIEFER

AND

STEPHEN LASHER

Table of Contents

I. Introduction and Qualifications

Kristoffer P. Kiefer

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

A. My name is Kristoffer P. Kiefer. My business address is 300 Erie Boulevard West, Syracuse, New York 13202.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid USA Service Company, Inc. (Service Company), a subsidiary of National Grid USA (National Grid), and I currently hold the position of Director, AMI Customer, Business Integration, and Business Case Development. My responsibilities include leading the development of business cases and supporting materials as part of National Grid's effort to secure regulatory approval for the deployment of Advanced Metering Functionality (AMF) for its operating companies, including The Narragansett Electric Company d/b/a National Grid (the Company).

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Art in Political Science from the University of Rochester in 2002 and a Juris Doctor from Syracuse University College of Law in 2005. I began my career working for the law firm Snell & Wilmer LLP as an associate attorney from 2005 to 2010. From 2011 to 2016 I served as Legislative Counsel and General Counsel for two members of the United States Senate. In 2016 I began working for National Grid as

Senior Counsel I in the Legal Department. I began my current role with National Grid's Transformation Office in 2020.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (PUC) or any other regulatory commissions?

A. I have not testified before the PUC; however, I presented an update regarding the Company's AMF filing to the PUC at the Power Sector Transformation (PST) Technical Session on September 24, 2020. Also, I have testified before the New York Public Service Commission (NYPSC) on behalf of the Company's affiliate, Niagara Mohawk Power Corporation (NMPC), in its rate case filed on July 31, 2020, in Case Nos. 20-E-0380 and 20-G-0381.

<u>Stephen Lasher</u>

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

A. My name is Stephen Lasher. My business address is 447 Dexter Street, Providence, Rhode Island 02907.

Q. By whom are you employed and in what capacity?

A. I am employed by the Service Company and currently hold the position of Principal Engineer in the Grid Modernization Solutions Group under the US Electric Business Unit. My responsibilities include supporting the Company's transition to the modern grid through identification and evaluation of potential next opportunities, technologies, or processes to provide measurable value to customers in Rhode Island.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Cincinnati with a Bachelor of Science Degree in Civil and Environmental Engineering in 1997, and from the Massachusetts Institute of Technology with a Master of Science Degree in Mechanical Engineering in 1999.

I joined National Grid in 2016 as a Principal Engineer in the Advanced Grid Engineering Group under the New Energy Solutions Business Unit. My responsibilities have included the following: technical lead for NMPC's Reforming the Energy Vision (REV) Distributed System Platform (DSP) Demonstration Project in Buffalo, New York; technical lead for National Grid's Non-Wires Alternative (NWA) project deferral calculations; co-author of National Grid's Grid Modernization Strategy Roadmap; and the business lead for the Company's Grid Modernization Plan (GMP).

Prior to joining National Grid, I spent nearly two decades working on projects relating to clean and emerging energy technologies, including solar energy, smart grid, energy storage, electric vehicle, and microgrid projects. From 1999 to 2010, I was employed by Arthur D. Little Inc. and later by TIAX LLC, both Cambridge, Massachusetts-based consulting and technology development companies, as an Engineer, Program Manager, Group Manager, and Business Development Leader.

From 2010 to 2012, I was employed by Satcon Technology Corporation, a Boston-based solar inverter company, as their Director of Business Development for Research and Development and later as their Director of Product Management for Central Inverters.

From 2012 to 2014, I worked as a consultant to small businesses, providing technical and market insights, driving new product development programs, and helping capture new business and outside funding opportunities for the development and commercialization of emerging energy technologies.

From 2014 to 2015, I was employed by eNow Inc., a Warwick, Rhode Island-based manufacturer of solar power solutions for the transportation sector, as its Vice President of Business Development.

Immediately prior to joining National Grid, from 2015 to 2016, I was employed by Sensata Technologies, Inc., an Attleboro, Massachusetts-based supplier of sensors and controls for a broad range of markets and applications, as their North American Market Manager for Performance Sensors.

Q. Have you previously testified before the PUC or any other regulatory commissions?

A. Yes, I testified regarding the Volt-VAR optimization (VVO) program as part of the fiscal year (FY) 2021 Infrastructure, Safety and Reliability Plan in Docket No. 4995. Also, I presented updates regarding the Company's Grid Modernization Plan (GMP) filing to the PUC at the Power Sector Transformation (PST) Workshop on April 9, 2019 and the PUC Technical Sessions held on November 5, 2019 and September 24, 2020.

II. Purpose and Structure of Testimony

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

A. The purpose of our joint testimony is to present the Company's proposal to implement AMF in Rhode Island, as supported by the Updated AMF Business Case.

In the Company's November 28, 2017 Power Sector Transformation (PST) Plan filing in Docket No. 4780, the Company submitted a preliminary AMF business case and benefit-cost analysis (BCA).[1] The Amended Settlement Agreement (ASA) approved by the PUC at its Open Meeting on August 24, 2018, in Docket No. 4770, provided $2 million in funding for the Company to develop the Updated AMF Business Case and established the PST Advisory Group, a stakeholder process, to develop and refine the AMF implementation proposal.

[1] *See The Narragansett Elec. Co. d/b/a National Grid, Proposed Power Sector Transformation Vision and Implementation Plan*, Docket No. 4780, , Book 1 of 3, Schedule PST-1, Ch. 4 at Bates 68-99, Appendix 2.1 at Bates 192 (November 28, 2017).

Article II, Section C.16 of the ASA required the Company to file the Updated AMF Business Case with the PUC for review and approval of the funding necessary to deploy AMF statewide.

Q. Does the Company's Updated AMF Business Case meet the requirements of the ASA?

A. Yes. The Updated AMF Business Case addresses each element required by Article II, Section C.16.iv of the ASA. Additionally, the Company has incorporated other areas that have arisen through the stakeholder engagement process. Table 2-1 in the Updated AMF Business Case identifies the specific sections of the Updated AMF Business Case in which each element is addressed, as well as a summary of the results of the stakeholder engagement process relative to each element. The stakeholder engagement process is discussed in more detail in Section III of our joint testimony.

Q. What does the Company seek from the PUC with this filing?

A. With this filing, the Company requests that the PUC approve the Company's proposal to implement AMF in Rhode Island and the associated cost recovery. The investment in AMF forms a foundational component of the Company's proposed GMP, which the Company is filing concurrent with the filing of this proposal. The investments outlined in the GMP are necessary to manage the distribution system with more granularity to create a platform of solutions that enables more distributed energy resources (DERs) to connect, while also giving customers more control over their energy decisions, reducing energy use, and improving reliability. Additionally, the Company's proposed AMF implementation timeline aligns with the need to replace the majority of the current Rhode Island electric metering technology, which has either reached its expected end of life or will do so in the next couple of years.

Q. How is your testimony structured?

A. Sections I and II include an Introduction and the Purpose and Structure of the Testimony, respectively. Section III presents the case for AMF in Rhode Island, including why now is the best time to invest in AMF technologies based on the state of metering in Rhode Island (i.e., inaction is not an option), as well as changing customer and grid needs. Section III also provides an overview of the development of the Company's AMF proposal and the significant stakeholder contributions made throughout the process. Section IV discusses the relationship between AMF and grid modernization and, specifically, how the Updated AMF Business Case is integrated with the Company's GMP to create one holistic plan. Section V provides an overview of the proposed AMF Program, including the functionalities that will be available through an AMF deployment, as well as the details of program implementation. Section VI presents the AMF BCA. Section VII summarizes the Company's proposal for cost-recovery, which includes a request to reopen the multi-year rate plan (MRP) to propose the recovery of the revenue requirement for approved AMF investments in accordance with Article II, Section C.16.c of the approved ASA.[2] Section VIII outlines the Company's Customer Engagement Plan. Section IX summarizes the Company's approach to Data Governance. Section X presents the Company's proposed Metrics and Performance Incentive Mechanisms. Finally, Section XI is the conclusion.

Q. Are you sponsoring any attachments in support of your joint testimony?

A. Yes, we are sponsoring the following attachments:

- Schedule KPK/SL-1 is the Updated AMF Business Case, which includes the following attachments:
  - Attachment A is the Customer Engagement Plan;
  - Attachment B is the Data Governance Plan;
  - Attachment C is the Time-Varying Rates Overview;
  - Attachment D is the Metrics and Performance Incentives Measures Roadmap; and
  - Attachment E is the Benefit Cost Analysis (BCA) Model – **CONFIDENTIAL**.

III. The Case for AMF in Rhode Island

Q. Please describe the Company's current metering capabilities in Rhode Island.

A. The Company provides energy delivery services to approximately 496,000 electric customers across 38 cities and towns in Rhode Island and 272,000 natural gas customers in 33 cities and towns in Rhode Island. Currently, the Company's electric metering

[2] *See* Docket Nos. 4770/4780, Report and Order No. 23823 (May 5, 2020) (approving the Amended Settlement Agreement dated August 16, 2018 pursuant to an Open Meeting decision on August 24, 2018).

infrastructure has limited ability to meet the evolving and diverse needs of its customers. Most meters in Rhode Island use automated meter reading (AMR) technology. Deployed in the early 2000s to replace manual meter reading processes, this technology sends a radio signal to a fleet of service vans as they drive by to collect monthly reads. The AMR technology contains core features that the Company relies on for identifying customer load, billing customers appropriately based on their electricity consumption, and managing customer connections to the Company's infrastructure. Approximately 60 percent of the electric AMR meters currently in the field will reach their estimated 20-year life on or before calendar years 2023-2024.

Q. What is AMF?

A. AMF refers to four key advanced metering elements: 1) an integrated network of smart electric meters and gas modules capable of capturing customer energy usage data at defined intervals and supporting grid-edge applications; 2) a two-way communications network and related information technology (IT) infrastructure for transmitting the data and control signals using radio frequency and cellular communications technology; 3) a meter data management system (MDMS), IT platform, and cybersecurity protections to securely and efficiently collect, validate, store, and manage the meter data; and 4) customer systems including billing and a customer energy management platform (CEMP) to provide energy usage data access, insights, and service offerings that enable customer energy management.

1) <u>Identifying the need for a new metering solution</u>

Q. Why is a new metering solution a necessary investment?

A. A new metering solution is required to address three unmet needs: i) evolving customer expectations; ii) replacement of existing electric AMR meters that are reaching the end of their useful lives; and iii) taking further meaningful actions to achieve shared clean energy goals.

Customers are increasingly seeking automated distribution system capabilities and enhanced access to energy information. AMR technology neither provides enhanced functionality nor does it provide energy usage data with the granularity and frequency required to deliver energy insights, personalized energy efficiency, and demand response to customers. With AMF, however, the Company believes it can meet evolving customer needs, using the two-way communication capabilities to enable remote connections, provide enhanced time-varying rate (TVR) structures that can be remotely programmed, conduct remote meter investigations, and enhance outage management.

From an operational perspective, the Company needs to address its existing electric AMR metering assets – approximately 60 percent of which are reaching the end of their useful life. In this way, doing nothing is not an option. Indeed, a rough estimate using the Company's BCA suggests that more than half of the long-term AMF bill impacts are unavoidable, because of the costs that would be incurred to replace the AMR metering assets. Moreover, in the absence of AMF, additional investments in grid modernization efforts (e.g., more feeder sensors) would also be necessary to provide enhanced information on the grid that would have been handled through AMF devices. Therefore, investing in AMF now addresses this key operational need while paving the way for enhanced functionality. In addition, investing in AMF mitigates the risk of sunk costs that could be incurred from re-investing in AMR technology, which is incapable of meeting the needs of a modern electric grid, and is becoming increasingly obsolete with projections showing 107 million AMF meters deployed nationwide.

Q. Please elaborate on how customer needs are changing.

A. Industry research and customer survey results suggest that customer expectations of their utility are expanding. Customers expect their utility to provide reliable, safe, clean, and affordable energy while also providing access to actionable information, giving customers greater choice and control over their energy usage, and delivering energy services in a simple and convenient way. In addition, the Company's customers:

- Express a willingness to alter energy use to achieve savings;
- Want to easily access their energy usage data from a variety of channels;
- Have an interest in using connected devices to enable greater control over the energy coming into their homes;
- Desire tailored, personalized choices for energy consumption options; and
- Need convenient energy services and solutions.

Q. Please elaborate on how the needs of the electric distribution grid are changing.

A. Significant change is occurring across the energy industry due to changing customer behavior and expectations, including increasing adoption of distributed energy resources (DERs), such as renewable distributed generation (DG), beneficial electrification, electric vehicles (EVs), electric heat pumps, and advanced "smart" technologies to actively manage energy use in customers' homes and places of business.

The electric industry expects this trend will continue and will likely escalate as customers' expectations and technologies continue to evolve. As customers adopt more DERs and engage in load management programs to manage their energy needs, the distribution system is becoming more dynamic and complex. Each new DER interconnection has a physical impact on the grid and creates new challenges and opportunities for distribution system planning and operations.

Historically, power has flowed predominantly in only one direction and has been forecasted based on long-term trends. One-way power flow has meant that distribution equipment has required only local autonomous control settings that do not need to be remotely monitored or controlled in a timely fashion. As a result, there is currently little real-time visibility of the grid downstream of the substation, which limits the distribution utility's ability to monitor distribution loading and voltage and communicate energy usage information to customers. Going forward, the grid needs to be managed more granularly, both in time and location, to continue to serve customers safely and reliably. AMF will help to address these long-term trends.

2) <u>Evaluating and refining a solution to address the metering need</u>

Q. Did the Company consider metering solutions other than AMF?

A. Yes. The Company implemented a two-step evaluation process to determine the relative merits and cost effectiveness of a variety of customer, grid, and meter-level technology solutions. In the first step, the Company identified and compared metering technology solution options and complementary customer and grid technologies to determine which options met the capability requirements of a modernized grid. In the second step, the Company compared the relative economics of the solutions meeting that threshold. The solutions evaluated by the Company included:

- Current AMR meters;
- Targeted/enhanced AMR meters;
- Targeted AMF Deployment;
- Full AMF Deployment;
- End-User Solutions;
- Transformer-Level Sensors; and
- Pole-Top Readers.

Section 5.1 of the Updated AMF Business Case provides a detailed analysis of the different solutions, with Table 5-1comparing the functionality of the various solutions.

Q. What did the Company conclude based on this functionality assessment?

A. The Company's functionality assessment identified full AMF deployment as the only fit-for-purpose solution to meet the objectives and capabilities for a well-coordinated and integrated GMP.

The Company found that AMR technology does not provide any of the customer-facing functionalities that enhance customer energy management or the grid-facing functionalities that support the improved system operations, planning, and DER integration required in a changing energy landscape. Conversely, customer- and grid-facing technologies, other than AMF meters, can provide a subset of the functionalities available from full-scale AMF deployment, but they cannot deliver the required revenue-grade billing determinants. Instead, these non-meter technology platforms drive increased customer costs without alleviating the need to replace the existing AMR meters or the need for additional investments to support a well-coordinated and integrated GMP. In addition, the BCA discussed in Section 8 of the Updated AMF Business Case outlines the incremental benefits AMF can deliver, while defining the cost differential required to implement full-scale AMF above an AMR meter replacement program.

Q. Did the Company consider multiple asset and telecommunication ownership and service options for implementing AMF?

A. Yes, the Company, with the support of an external consultant, undertook an assessment of different ownership and service options, referred to as "business models," for components of the AMF solution as proposed in its PST Plan in Docket No. 4780.

Q. What business model alternatives were considered in that assessment?

A. The assessment considered the full spectrum of ownership and operational options for third-party services, referred to "as-a-service" offerings, across the software, telecommunications, and meter components of the AMF solution. As-a-service offerings aim to reduce upfront costs and the total cost of ownership, while also ensuring that utilities have access to the latest technologies and periodic software upgrades. On the other hand, such models decrease a utility's control over future technology development and represent new commercial contracting risks. For this reason, the Company's consultant undertook extensive market research to look at approximately 40 alternative ownership examples of utility advanced metering networks (i.e., electric, gas, and water). These options are described in additional detail in Section 6 of the Updated AMF Business Case.

Q. What were the findings of the business model assessment?

A. The assessment found that the Company's AMF ownership model proposed in its PST Plan filing was an innovative and cost-effective approach to AMF. The Company's current proposal includes "as-a-service" approaches for the wide-area network (WAN) and back-office IT systems and may consider meter installation services during the detailed meter deployment planning phase. This approach is consistent with the assessment's compiled market research. Other alternative options evaluated as part of the business model assessment were either not cost-effective or represented significant implementation risk due to the market maturity of the option.

3) Value for Customers, the system, and advancing clean energy goals

Q. Does the Company expect the proposed AMF solution to deliver value for customers, the distribution system, and the Rhode Island clean energy goals?

A. Yes. AMF will deliver new functionalities that provide significant benefits to customers and the distribution system and that will move the State closer to shared clean energy goals. A description of these customer, system, and environmental benefits is included in Section 1.3 of the Updated AMF Business Case. Sections IV and V of this joint testimony also discusses the AMF-enabled functionalities in more detail.

Q. How did the Company evaluate the value of the proposed AMF investment?

A. To quantify and evaluate the benefits of the proposed investment, the Company developed the AMF BCA consistent with the PUC's goals and Benefit-Cost Framework that the PUC adopted in Docket No. 4600 (Docket 4600 Framework).[3] The BCA demonstrates that full-scale AMF deployment can deliver total benefits of approximately $533 million (opt-out) and $416 million (opt-in) with BCA ratios of 2.38 and 1.91, respectively. This approach includes cost synergies based on a multi-jurisdictional Rhode Island and New York (RI+NY) deployment.[4]

The AMF BCA is further discussed in Section VI of our joint testimony and Section 8 of the Updated AMF Business Case.

Q. How does the Updated AMF Business Case ensure accountability by the Company?

A. The Company believes that the success of delivering value to customers is bolstered through effective program reporting and management. For the purposes of tracking and reporting AMF implementation costs, the Company is proposing to file an AMF Program Report with the Commission on a semi-annual fiscal-year basis. The reporting will provide transparency to stakeholders on the efficiency and effectiveness of the

[3] *See Investigation Into the Changing Electric Distrib. Sys. and the Modernization of Rates In Light of the Changing Distrib. Sys.*, Docket No. 4600, Report and Order No. 22851 (July 31, 2017).

[4] There is also an opportunity to realize additional cost synergies if the Massachusetts Department of Public Utilities were to approve AMF/AMI deployment for the Company's Massachusetts affiliate. The nature and extent of the cost synergies, however, is dependent on the technology adopted in each respective jurisdiction and the timing of the proposed AMF/AMI deployments.

implementation and allow the Company to work through any questions or issues that may arise in a timely manner.

The Company has also taken a comprehensive approach to ensure that customers realize the envisioned benefits of the AMF program. These steps include: i) a long-term integrated GMP and AMF roadmap evaluated on a benefit-cost basis to ensure the timing and associated costs of new functionalities are aligned with system and customer needs; ii) consideration of alternative metering solutions and a comparison with the proposed AMF solution based on relative functionalities, benefits, and costs; iii) a procurement process for the AMF solution, evaluating functionalities and flexibility to address technology obsolescence risk; iv) refined cost estimates through a Request for Solution (RFS) solicitation for the major components of the AMF solution, including the electric meters, gas modules, field area network (FAN) equipment, back-office systems, and related professional services to enhance cost certainty; v) refinement of costs and benefits; vi) development of a comprehensive customer engagement plan; vii) development of a roadmap of proposed metrics and performance incentive measures to measure the progress and effectiveness of the Company's planned AMF deployment; viii) work toward developing a project governance structure; and ix) a proposal, as discussed in Section X of our joint testimony, which guarantees certain benefits to customers and increases the Company's accountability to deliver the AMF solution in line with the Updated AMF Business Case assumptions.

Q. What will the AMF Program Report entail?

A. The semi-annual AMF Program Report will address the status of AMF deployment and include the following elements: i) a narrative explaining overall AMF implementation status; ii) detail on actual spending relative to the AMF budget; iii) identification of allocations of AMF costs to the Company, as appropriate; iv) explanations of variances between budgets and actual spending; and v) metrics reporting in areas such as program implementation, customer engagement, operations, and third-party engagement, which are discussed in more detail in Section 9 and Attachment D of the Updated AMF Business Case. Once a year, in the AMF Program Report filed within 60 days of the end of the fiscal year, the Company will also include the following information: i) any cost or timeline differences that exceed ten percent for the fiscal year; and ii) the latest AMF sanction paper authorized during the fiscal year. The Company also proposes to hold semi-annual meetings with the Rhode Island Division of Public Utilities and Carriers (the Division) and the Rhode Island Office of Energy Resources (OER) to review the AMF Program Report submissions.

4) Stakeholder Engagement Process

Q. How did the Company facilitate stakeholder engagement in the development of the Updated AMF Business Case?

A. As provided for in Article II, Section C.17.e of the ASA, the Company convened the PST Advisory Group on October 26, 2018, in partnership with the Division and OER, and formed the GMP and AMF Subcommittee to gather stakeholder input for the development of the Updated AMF Business Case and GMP. Subcommittee members include representatives with environmental and clean energy interests, low-income community advocates, Non-regulated Power Producers (NPPs), and representatives from community interests, as provided in the ASA.

The meetings covered all topic areas identified in the ASA, as well as additional topics raised by stakeholders. The initial phase of formal meetings was held between November 2018 and January 2019. The formal meetings covered specific topics to garner initial stakeholder input and seek alignment of proposals laid out by the Company, such as updated schedules, customer value streams, and alignment with Docket No. 4600, among others. The second phase of meetings, held between February 2019 and March 2020, sought to continue reviewing and refining the Company's proposals while providing additional opportunities for stakeholders to provide feedback on key elements of the Company's plan, including a review of key filing deliverables. Figure 2-1 of the Updated AMF Business Case details the Subcommittee meeting schedule from November 2018 through September 2020. Figure 2-1 provides an overview of the PST Subcommittee workplan and schedule. Table 2-1 summarizes stakeholder feedback regarding each of the AMF-related requirements in the ASA.

In addition, the PUC held a PST Workshop on April 9, 2019, and Technical Sessions on November 5, 2019 and September 24, 2020 to receive status updates on the work of the PST Advisory Group, including the GMP and AMF Subcommittee. The PUC presented feedback during an open meeting following the April 9, 2019 Working Group session. The Company has worked to incorporate that feedback, together with stakeholder feedback, into the Updated AMF Business Case and the broader GMP.

This approximately two-year long collaborative process provided a valuable opportunity to gather and incorporate stakeholder input into the development of all aspects of the Company's proposal. To that end, the Company sought to drive meaningful discussion among members of the GMP and AMF Subcommittee through transparency and responsiveness to stakeholder questions.

Q. How did the Company take feedback received in the PUC technical sessions into account?

A. The feedback from the PUC technical sessions, combined with additional subsequent feedback from the GMP and AMF Subcommittee, was used to refine the relevant sections of the Updated AMF Business Case or create new sections to address the concerns raised by the PUC. In response to this feedback, the Company added sections addressing health concerns (Section 5.4) and establishing a tighter integration between the AMF and GMP proposals (Section 4). Likewise, the Company revised sections of the Updated AMF

Business Case to address concerns regarding the analysis of external factors that could impact the benefits in the BCA (e.g., net metering and community choice aggregation), and the potential for obsolescence. These items are addressed in more detail in Section 2.1 of the Updated AMF Business Case.

Q. How did the Company take stakeholder feedback and concerns into account?

A. Based on stakeholder input, the Company ran multiple BCA scenarios, refined benefit assumptions, developed more granular cost allocators, and crafted the thoughtful and robust approach to customer engagement reflected in the Customer Engagement Plan. In all, the exchange of ideas that occurred through the GMP and AMF Subcommittee served to confirm the Company's commitment to deploying AMF as a foundational grid modernization investment, while also helping the Company refine its proposal in important ways, including:

- Development of the Customer Engagement Plan and plans for the Company's Energy Innovation Hub to guide customers through the awareness, deployment, and enablement phases of customer engagement;
- Drafting of a comprehensive Data Governance and Management Plan;
- Development of a cost allocation proposal;
- Inclusion of additional information on future gas application opportunities (e.g., demand response, remote shut-off valves);
- Increased specificity of AMF functionalities; and

- Addressed concerns around benefits realization, community choice aggregation, remote net metering, and obsolescence.

IV. Integration of AMF and Grid Modernization

Q. Please explain the foundational importance of AMF to grid modernization.

A. The Company's Updated AMF Business Case is an integral part of the GMP. Although the one-way electric power system has served utility customers well for decades, advances in technology, changing customer expectations, and initiatives focused at driving resource diversity, clean energy, and system efficiency are changing the way the electric distribution system is utilized. Thus, the way in which the electric distribution system is planned and operated must also change in a bi-directional and efficient manner.

The Company uses the term "grid modernization" to refer to those investments associated with managing the distribution system with more granularity to create a platform of solutions that enables more DERs to connect, while also giving customers more control over their energy decisions, reducing energy use, and improving reliability. To this end, the Company identified three overarching objectives for grid modernization in the GMP:

- Give customers more energy choices and information;
- Ensure reliable, safe, clean, and affordable energy to benefit Rhode Island customers over the long term; and
- Build a flexible grid to integrate more clean energy generation.

AMF provides foundational support for the grid modernization objectives. Through AMF, customers can obtain enhanced information, choice, and control over their electricity consumption, enabling them to reduce their energy bills through greater insights into their energy cost drivers and personal usage, and through new product and service offerings. The granular and timely energy information and remote capabilities also support grid-side applications through more efficient operation of the distribution system, resource diversity, and integration of DG today and into the future.

Section 4 of the Updated AMF Business Case and the GMP Business Case provide additional detail regarding the Company's approach and methodology for developing the GMP objectives, and the role for AMF.

Q. Please describe how AMF enables the grid modernization functionalities set forth in the GMP.

A. The GMP filing identifies 15 key grid modernization functionalities (See Table 5.3 of the GMP Business Case). AMF is foundational to many of the key grid modernization functionalities and provides significant enhancement to several others, allowing for better observability, planning, and control of the distribution system and DERs. In this context, "foundational" means that the grid modernization functionality would not be possible without AMF. For example, AMF is foundational to three key grid modernization functionalities:

- Customer Information: AMF enables the timely, granular energy usage information for all customer classes using either the Company's proposed Customer Energy Management Platform (CEMP) or through a Wi-Fi-enabled home-area network (HAN). Through the CEMP, customers will be able to access and utilize energy information and savings tools, receive personalized energy insights, and, if they choose, share their energy usage data with authorized third-parties using Green Button Connect My Data (Green Button Connect), which will support the development of new innovative service offerings. The CEMP is discussed in further detail in Section VI of our joint testimony regarding the Customer Engagement Plan.
- Advanced Pricing: AMF provides the interval energy usage data required to support TVR and customer load management programs.
- Remote Metering: AMF improves operational efficiency by eliminating operation and maintenance (O&M) costs associated with AMR meter reading, meter investigations, and site visits for connects and disconnects.

In addition, AMF provides enhancements to several grid modernization functionalities, such as observability (monitoring and sensing), power quality management, distribution grid control, grid optimization, reliability management and DER operational control through enhanced load and voltage data, automated outage and restoration notification, and operational telecommunications that enable the exchange of information and/or control with residential and small commercial DER technologies. AMF provides granular customer load data from internal power monitoring at the customer level, which provides a step change in data available for grid planning and operations. The data can be aligned with other system data to create loading and voltage profiles at all points along a feeder, leading to more detailed load and DER forecasts for planning and operational needs.

Table 4-2 in the Updated AMF Business Case describes in more detail how AMF enables the key GMP functionalities.

Q. What is the granularity and timeliness of the AMF energy usage data?

A. AMF technology has the capacity to capture and transmit raw energy usage data to customers using the CEMP at 15-minute intervals with 30 to 45-minute latency[5] for electric data and one-hour intervals with an eight-hour latency for gas data. In addition, AMF will allow customers to directly access raw (i.e., non-bill quality) energy usage data in real time using the HAN. With this functionality, customers will have access to actionable energy usage information during peak periods, receive additional energy insights, and have an opportunity to optimize savings from personalized EE and DR offerings.

[5] This latency is consistent with NYPSC's approval of the Company's New York affiliate's AMI proposal in New York.

V. AMF Program Overview

Q. Please describe the Company's proposed timeline for deployment of AMF.

A. Following PUC approval of the Updated AMF Business Case, the Company proposes a three and one-half-year phased deployment schedule, as shown in Figure 7-1 in the Updated AMF Business Case. Phase 1 consists of 24 months of detailed process design, procurement activities, organizational development, and back-office system installation and upgrades. This will involve building and testing end-to-end solutions, developing procedures and training materials, organizing implementation, including training field and office personnel, developing communication materials, and initiating the Customer Engagement Plan. Phase 2 consists of a 12-month deployment of the AMF mesh communications network and begins in the last quarter of Phase 1. Phase 3 commences after the completion of Phase 1 and consists of an 18-month deployment of AMF electric meters. As noted earlier, approximately 60 percent of the electric AMR meters currently in the field will reach the end of their estimated 20-year life during calendar years 2023-2024. To address this operational issue, the Company proposes to install approximately two-thirds of the electric AMF meters in the first year of Phase 3 deployment, followed by the remaining third of meters in the first six months of the second year of Phase 3 deployment. The age of the gas AMR communication modules is more evenly distributed, as the gas modules are routinely replaced as part of the existing 15-year gas meter replacement program. As such, AMF gas modules will be installed independent of

AMF electric meters, based on the AMR module life-cycle replacement program, which is estimated to occur over a period of 10 to 15 years.

Q. Have the Company's affiliates proposed AMF investments in their jurisdictions?

A. Yes. On November 20, 2020, the NYPSC approved the Company's upstate New York affiliate's proposal to deploy approximately 1.7 million electric AMF meters and 640,000 AMF-enabled gas modules.[6] On July 2, 2020, the Massachusetts Department of Public Utilities (DPU) initiated an investigation into the targeted deployment of AMF to enable TVR for EV customers.[7] The Company's affiliate filed two sets of comments and participated in four technical sessions, explaining the similar unmet needs that AMF can address in Massachusetts. The Company's affiliate is waiting further guidance from the DPU on next steps relative to assessing and proposing an AMF implementation plan for the Commonwealth.

Q. What are the AMF functionalities that will be available upon deployment of AMF to customers?

A. The AMF functionalities are divided into near-term and future functionalities based on when those functionalities are expected to be available. The following near-term

[6] *See* New York Public Service Commission Case 17-E-0238 and Case 17-G-0239, Order Authorizing Implementation of Advanced Metering Infrastructure With Modifications (November 20, 2020).

[7] *See Investigation by the Dep't of Pub. Util. on its own Motion into the Modernization of the Elec. Grid – Phase II,* Docket D.P.U. 20-69 (July 2, 2020).

functionalities are enabled by the initial AMF implementation and are included in the first five years of the Updated AMF Business Case: i) CEMP – Near Real Time Customer Data Access; ii) CEMP – Customer Energy Insights; iii) CEMP – Bill Alerts; iv) CEMP – Load Disaggregation; v) CEMP – Green Button Connect; vi) Integration with In-Home Technologies; vii) Time Varying Rates – Customer & DER; viii) Grid-Edge Computing; ix) Voltage Measurements; x) Outage Detection; xi) Remote Interval Meter Reading; xii) Remote Meter Configuration; xiii) Remote Meter Investigation; xiv) Remote Electric Connect and Disconnect; and xv) Theft Protection.

Except for TVR and outage detection, the Company proposes to develop and implement the near-term functionalities when meter installation begins in project year 3 (i.e., the beginning of deployment Phase 3). All benefits and costs associated with the near-term AMF functionalities are reflected in the BCA that is included with the Updated AMF Business Case. In addition, Table 5-6 of the Updated AMF Business Case provides a description of each of the future AMF functionalities.

Q. What are the AMF-enabled future functionalities?

A. Potential future AMF functionalities that rely on the grid-edge computing platform capabilities include: i) grid mapping/locational awareness; ii) real-time load disaggregation; iii) bypass theft detection; iv) intelligent voltage monitoring; v) distributed (i.e., grid-edge) outage detection; vi) temperature monitoring; vii) arc sensing; viii) high impedance detection; ix) broken neutral detection; and x) active DR.

These AMF-enabled future functionalities are in various stages of development and testing by AMF vendors. While these future functionalities are discussed qualitatively in the Updated AMF Business Case, neither the costs nor the benefits are included in the accompanying BCA. Table 5-6 of the Updated AMF Business Case provides a description of each of the future AMF functionalities.

Q. What opportunities does AMF provide for third-party market participation?

A. AMF will animate the market for third-party products and services by enabling customers to share energy usage information with authorized entities. With access to granular energy usage information, such third-parties may be able to develop and offer new products and services such as alternative TVR structures, demand response programs, and more. Furthermore, third-party market participants will be able to work directly with customers to manage energy usage, either by providing actionable insights or by providing customers with new in-home products that can connect to their meter through the HAN to monitor and manage energy usage in real-time.

Q. Please describe how full AMF deployment will enhance the Company's other customer-facing programs?

A. AMF deployment provides a unique opportunity to meet customers' evolving expectations by enhancing the Company's existing portfolio of customer-facing programs and services, ranging from offerings such as residential and commercial EE and DR to its comprehensive electric transportation initiative. It also presents an opportunity to maximize adoption and effectiveness of third-party technologies and services under policies and programs set forth by state laws and regulations. Through access to more granular energy usage information and energy insights, AMF will enable the Company to better design, target, and implement its key customer-centric offerings.

The Company has taken a conservative approach to assumptions about integration benefits with other programs in its BCA. As AMF is implemented, the Company expects the respective future program filings will leverage the new capabilities, reflecting the associated enhancements, savings estimates, and program delivery components.

Q. Has the Company addressed customer health and safety concerns regarding the AMF meters in the Updated AMF Business Case?

A. Yes. The Company recognizes that AMF meters have generated concerns about exposure to radio frequency. As a result, the Company has conducted research across government organizations, scientific studies, industry groups, consumer education non-profits, and court rulings, all of which have concluded that the low-level frequency produced by smart meters poses no credible health or safety threats to consumers. Section 5.4 of the Updated AMF Business Case summarizes these findings. Nevertheless, the Company's proposal affords customers who have these or other concerns the ability to opt-out of receiving an AMF meter.

Q. Are there any fees associated with opting out of receiving the AMF meter?

A. Yes. Similar to the Company's approach for customers who currently opt-out of receiving an AMR meter, customers who opt out of an AMF meter would be responsible for a monthly meter reading fee, as well as a one-time meter exchange fee if they choose to opt out after receiving an AMF meter.

Q. How does the Company's Updated AMF Business Case address concerns about technology obsolescence?

A. Stakeholders have expressed concerned about the longevity of the Company's AMF solution given the long payback periods and changing customer and electric distribution needs. The Company takes these concerns seriously and has evaluated the capabilities and technology roadmaps of the AMF vendors as part of the procurement effort to mitigate this risk. The Company's proposed solution represents the latest generation of AMF technology. This technology maximizes future flexibility and adaptability because the meters support over-the-air firmware upgrades and grid-edge computing platform capabilities. This means that supporting software applications and updates can be deployed remotely to the meters. This capability mitigates the risk of technology obsolescence and bolsters the ability to tailor subsequent solutions to meet evolving needs.

Q. How will the Company manage the AMF program?

A. The Company will implement industry standard project management practices and complete thorough business unit engagement activities to maintain continuity throughout the project. The AMF program governance structure will include representation from senior leadership and subject matter experts from across the Company. A dedicated Steering Committee comprised of business and IT program sponsors as well as senior leadership will provide strategic oversight. The Steering Committee will provide guidance to the program and alignment across Company priorities such as grid modernization. In addition, the Steering Committee will oversee the delivery of benefits, facilitate program staffing, and ensure proper risk mitigation and management.

The Company will also establish a project management office (PMO) directly linked to workstreams, serving as the conduit between the project front line and the Steering Committee. The PMO will be composed of Company employees supported by consultants, who can provide industry leading perspective and experience. The PMO will have broad project responsibilities including providing oversight and direction to overall program activities, fiscal oversight, local resolution, critical updates to stakeholders, and management of an integrated project schedule with defined milestones. The PMO will also use a decision matrix to determine which risks and key decisions should be escalated for senior-level resolution.

Q. What is the status of the Company's vendor selection process for implementing the AMF program?

A. The Company engaged in a competitive request for proposals process throughout all jurisdictions within the National Grid footprint to leverage volume pricing. The process included a request for information to identify qualified potential bidders. The request for proposals covered AMF electric meters and gas modules, FAN communications equipment, head-end and meter data management systems, and associated professional services. The Company completed a comprehensive total cost of ownership analysis of the qualified vendors in order to shortlist a preferred vendor. The Company is negotiating the master service level agreement terms and conditions with the down-selected vendor.

VI. Docket 4600 and Benefit-Cost Analysis

Q. Does the Updated AMF Business Case address the Docket 4600 Framework and goals that the PUC adopted in Docket No. 4600?

A. Yes. In Docket No. 4600, Investigation into the Changing Electric Distribution System (Docket 4600), the PUC adopted goals for a new electric system, the Docket 4600 Framework, and the rate design principles set forth in the Stakeholder report.[8] The PUC subsequently issued a guidance document (Guidance Document) that set out and explained the goals, rate design principles, and the Docket 4600 Framework for use in future dockets.[9] The Company developed the Updated AMF Business Case consistent with the Docket 4600 Framework. Table 4-3 in the Updated AMF Business Case addresses how the GMP investments, including AMF, advance/detract from/are neutral to each of the goals set forth in the Guidance Document. Likewise, Appendix 10.7 maps specific AMF functionalities and GMP objectives to each Docket 4600 goal.

The PUC also held that the Docket 4600 Framework should serve as the starting point in making a business case for a proposal, but that it need not be the exclusive measure of whether a specific proposal is reasonable and should be approved, recognizing that other factors may require consideration in addition to cost-effectiveness.[10]

[8] *See* Report and Order No. 22851, *supra* note 3 at 29.
[9] *See Pub. Util. Comm'n's Guidance on Goals, Principles and Values for Matters Involving the Narragansett Elec. Co. d/b/a National Grid*, Docket 4600-A (October 27, 2017).

[10] *See* Report and Order No. 22851, *supra* note 3 at 23.

The cost-effectiveness test upon which the Docket 4600 Framework is based is known as the "Rhode Island Test." Because the Rhode Island Test is intended to evaluate a variety of programs, the Docket 4600 Framework includes a wide array of categories for consideration, some of which will be more or less applicable depending on the proposal. Specifically, the benefit categories that are most relevant are based on AMF capabilities, such as the ability to read meters remotely, or implement TVR. The Company has applied the Docket 4600 Framework to the BCA that it used to evaluate the cost-effectiveness of the proposed AMF investment. Also, Table 8-1 of the Updated AMF Business Case lists each benefit category of the Docket 4600 Framework and indicates whether the category is quantified in the BCA. For those benefits not included in the BCA, the table provides the reason for exclusion. We discuss the BCA model and results in more detail below.

Q. Please describe the BCA for the proposed AMF investments as presented in the Updated AMF Business Case.

A. The Updated AMF Business Case contains the results of the BCA the Company developed to determine the cost-effectiveness of full-scale AMF deployment consistent with the Docket 4600 Framework. The Company isolated the effects of benefit considerations incremental to the past results presented in its PST Plan in Docket No. 4780 to emphasize the impact of fully applying the Docket 4600 Framework to the AMF BCA.

Section 8 of the Updated AMF Business Case presents the BCA in detail. Most AMF costs appear in the first four years (i.e., the back-office system, communication network, and meter deployment period). Years one and two contain costs associated with setting up back-office and IT systems to support the new meter functionality. Years three and four show a spike in costs associated with the actual meter capital and installations. As the meters are deployed, there is a corresponding benefit from avoided AMR costs. Following meter installation, O&M savings are realized in every year thereafter. Later year benefits increase as TVR is fully phased in and customer response reaches a steady state.[11] Based on this stream of costs and benefits over time, the AMF program has a payback period of just over six years.

Q. What are the costs associated with the Company's proposed AMF investments?

A. The total proposed investment is estimated to cost $224 million net present value (NPV) over 20 years (assuming the mid-point of an opt-out TVR scenario) and $218 million 20-year NPV (assuming the mid-point of an opt-in TVR scenario). The associated IT (e.g., head-end software, telecom, enterprise service bus, and cybersecurity costs) investment is embedded within the approximate $224 million (opt-out)/$218 million (opt-in) total investment in the BCA, with approximately $194 million (opt-out)/$188 million (opt-in) allocated to the electric business (e.g., meter equipment and installation costs, project management, customer engagement, etc.), and approximately $30 million (both opt-out

[11] Note that the Company does not propose implementation of TVR in connection with this filing. The Company will file a TVR proposal as part of the next suitable future filing before the AMF solution becomes operational.

and opt-in) allocated to the gas business. The approximate total costs for the program are broken into four primary cost categories:

- AMF Meters and Installation: $86 million
- Communications Network Equipment and Installation: $4 million
- Platform and Ongoing IT Operations: $74 million
- Customer Systems, including billing and CEMP: $60 million (opt-out), $54 million (opt-in).

Q. Please explain the updates the Company made to the BCA in the Updated AMF Business Case from that presented in the 2017 PST Plan filing in Docket No. 4780.

A. The Company updated the BCA in the Updated AMF Business Case from that presented in the 2017 PST Plan filing in Docket No. 4780 in several ways. First, the Company updated forecasts of key inputs to the benefits, revised the costs based on its procurement efforts, and refined some calculation methods. Second, the Company expanded the application of the Docket 4600 Framework, resulting in a more complete list of benefits.

The original list of benefits included avoided CO2 emissions, TVR benefits, Load Reductions, avoided O&M costs, and avoided AMR costs. Application of the Docket 4600 Framework resulted in increased benefits in these categories. In addition, the benefits now include NOx and SOx benefits, benefits from the avoided costs for additional sensors, customer outage benefits, transmission and distribution benefits, and intrastate demand reduction induced price effect (DRIPE) benefits. By adding these benefits, the benefit-cost ratio rose for the opt-out TVR scenario to 2.38. The waterfall chart in Figure 8-3 of the Updated AMF Business Case compares the previous BCA results to the current BCA results for opt-out TVR enrollment. Also, Appendix 10.5 provides a full list of the categories listed in the Docket 4600 Framework and the Company's consideration of each.

Q. What are the summary results of the BCA for full-scale deployment of AMF?

A. With co-deployment with the upstate New York affiliate, the BCA ratio is 2.38 (opt-out) and 1.91 (opt-in). These ratios show that implementing AMF in Rhode Island is cost effective and beneficial for customers.

Q. Which sensitivities did the Company consider in the BCA?

A. There are elements that feed into the BCA that are outside of the Company's control. One example is customer behavior, which can be influenced by marketing, education, and outreach campaigns.

To capture the uncertainty of these unknown and largely uncontrollable factors, the BCA presents four cases meant to bookend possible outcomes of benefit realization. The sensitivities are summarized in Table 8-2 of the Updated AMF Business Case. They include different scenarios around TVR enrollment, as well as customer response to TVR and usage insights/bill alerts. The Company includes these sensitivities because the assumptions are considered the most uncertain with potentially large impacts; while other uncertainties exist, none are expected to have as wide ranging of an effect on the BCA. The BCA model includes high- and low-customer response cases for each TVR enrollment case to account for customer price response uncertainty. The details of the assumptions used for the high-and low-response cases appear in Table 8-4 of the Updated AMF Business Case. Most of the BCA results correspond to the midpoint between high- and low-customer response levels. The Company also considered alterations to the BCA that included the following sensitivities: economic development impacts, low DER adoption, revenue benefits of AMF, rest-of-pool (ROP) DRIPE effects, and the use of a lower societal discount rate. Figure 8-15 provides the range of BCA ratios for each sensitivity. All sensitivities maintain high enough benefits, even at the low end, to remain cost effective (i.e., greater than 1.0).

Q. What are the expected quantified benefits from the AMF investments?

A. The total estimated benefits are $533 million 20-year NPV (assuming the mid-point of an opt-out TVR scenario) and $416 million (assuming the mid-point of an opt-in TVR scenario). The Company categorized the quantifiable benefits from the AMF investments as follows:

- Avoided O&M Costs: $45 million
- Avoided AMR Costs: $103 million

- Customer Benefits: $322 million (opt-out), $207 million (opt-in)
- Societal Benefits: $63 million (opt-out), $61 million (opt-in)

Table 8-6 in the Updated AMF Business Case shows the estimated 20-year NPV benefits for each of these categories for different TVR participation and response cases. The customer benefits category accounts for approximately 60 percent of benefits in the TVR opt-out case (50 percent for opt-in). A large portion of the societal benefits are tied to customer benefits as well, as changes in customer usage drive decreases in emissions. Thus, these two categories vary with differing assumptions of TVR enrollment and customer response. On the other hand, the Avoided AMR and Avoided O&M benefit categories do not vary by TVR scenario. Section 8.4 of the Updated AMF Business Case describes these benefits in more detail.

Q. Are there any other benefits expected from the deployment of AMF that have not been quantified?

A. Yes. There are a number of potential future benefits from the deployment of AMF that have not been quantified for the Updated AMF Business Case. One such benefit is the opportunity to integrate other end-point devices (e.g., smart street lights and smart remote methane detectors) using the AMF communications network and back-office systems. Section 5.3.3 of the Updated AMF Business Case provides an overview of end-point devices that could be integrated in the future. Another such qualitative benefit is tied to electric transportation. The Company is currently implementing a comprehensive Electric Transportation initiative as approved in Docket No. 4770. As that program is geared generally toward helping improve customer adoption and utilization of EVs, the Company has not forecasted any benefits from AMF in terms of helping to accelerate EV adoption. The BCA does, however, include an estimated benefit due to customers shifting EV charging patterns in response to TVR.

Q. Is the Company proposing a specific TVR structure as part of this proposal?

A. No. The ASA required the Company to include in the Updated AMF Business Case "assumptions upon which a proposal to develop time varying rates will be based" and also stated that "the Company's Updated AMF Business Case and associated Company proposals in relation to time varying rates will be subject to consideration by the PUC in a separate docket, and all interested parties will have an opportunity to participate in any process provided prior to PUC action on the Updated AMF Business Case and proposals contained therein." Although the Company did include an illustrative TVR to develop the BCA, the Updated AMF Business Case does not contain a TVR proposal. The Company will make such a proposal in the next suitable filing before the AMF solution becomes operational.

Q. How does TVR impact the BCA?

A. As mentioned, for purposes of estimating the TVR benefits within the Updated AMF Business Case and supporting BCA, the Company presents benefits from an illustrative Time-of-Use/Critical-Peak-Pricing (TOU/CPP) supply rate with other rate designs discussed qualitatively and with quantitative sensitivities around response to the TVR design. The rate considered is technology-neutral and designed for the residential class only (i.e., all TVR benefits modeled in the BCA are brought about by this single design and come only from residential usage). The TVR savings modeled do not assume adoption of any additional technology such as in-home displays or smart appliances; therefore, the estimated savings should be accessible to all customers.

Plausible benefits estimated from the Company's affiliates' TVR pilot programs and a survey of programs across the United States suggest that a TOU/CPP supply rate design, or another design that performs at least as well, achieves benefits large enough to create a cost-effective AMF proposal. The Company therefore believes that the approach to estimating TVR benefits in the BCA establishes a threshold level of customer net benefits that alternative TVR designs should be required to meet in any forthcoming TVR docket.

Appendix 10.4 and Attachment C of the Updated AMF Business Case provide details on the TOU/CPP design and customer response to the rate that combine to calculate the TVR benefits listed in the BCA.

VII. Cost Recovery

Q. How does the Company propose to recover the costs associated with the AMF proposal?

A. Under the ASA, the multi-year rate plan may be re-opened to adjust the Company's approved base distribution rates to recover incremental Narragansett Electric and Narragansett Gas revenue requirements associated with approved AMF initiatives. With the NYPSC's approval of the AMI proposal of the Company's upstate New York affiliate, Rhode Island and New York are expected to realize cost savings due to fixed cost sharing opportunities, increased purchasing scale, and full-time-employee sharing between jurisdictions. However, the extent of the multi-jurisdictional cost synergies depends on the AMF solution adopted by each respective jurisdiction and the timing of their deployment. The current timelines in this business case would allow for these synergies. The Company's revenue requirements, proposed distribution rates, and bill impacts reflect a shared allocation of applicable back-office IS systems costs assuming the same solution is adopted on a timeline that enables realization of full synergies. This proposal is presented in more detail in the pre-filed joint testimony of the Revenue Requirements and Pricing Panel. Also, Table 8-5 of the Updated AMF Business Case summarizes the components where the Company can recognize cost synergies, along with the factors driving the synergy.

Q. How does the Company propose to address unrecovered AMR asset costs?

A. The Company has installed or replaced (and continues to do so) a subset of electric AMR meters since the initial AMR deployment began approximately 20 years ago. The installations and replacements are used for situations, such as new customer growth, meter testing requirements, and meter failures. There is a resulting undepreciated investment in the legacy metering assets. The Company proposes to amortize the unrecovered investment over a specific period of time to be determined in its next depreciation study and rate case.

VIII. <u>Customer Engagement Plan</u>

Q. Please describe the Company's Customer Engagement Plan.

A. The objective of the Customer Engagement Plan is to inform and educate the Company's customers on AMF implementation and the benefits of smart meters, to increase acceptance of the new meters, increase participation in future innovative rate structures that align customer benefits with clean-energy objectives, and to empower customers to use new insights and services provided by AMF. Customer enablement and engagement are critical to achieving the benefits of AMF; therefore, the Company's Customer Engagement Plan provides a robust roadmap intended to guide customers through the three phases of the planned AMF deployment.

Q. How will the Company execute on its Customer Engagement Plan?

A. The Customer Engagement Plan consists of three phases: Phase 1 is customer awareness and education prior to meter installation; Phase 2 is the customer experience through deployment, including the ability to opt out of receiving a new AMF meter; and Phase 3 is empowering and enabling customers with AMF meters to maximize the functionality and benefits made possible by the new devices and future innovative pricing plans.

In Phase 1, the Company will build an extensive collection of informational materials and marketing collateral to support customer communication and engagement activities, educate and train internal Company employees, and begin a territory-wide customer and stakeholder outreach effort to build smart meter awareness, generate interest prior to meter installation, and address customer questions and concerns. Phase 1 will occur prior to deployment.

In Phase 2, the Company will build on the broad education base established in Phase 1 and narrow the focus of communication toward individual customers leading up to and during smart meter installation. This process will include specific tactical information to guide customers through the day of meter installation, including the timeline of events, what to expect, and alternate choices available, including opting out of meter installation.

In Phase 3, the Company will shift its focus to empowering and enabling customers to take full advantage of their new, more granular, timely energy usage data. The Company's CEMP, discussed above, as well as the HAN, will serve as customers' access point to their energy data. During this phase, the Company will facilitate customer interaction with third-party vendors who can help supplement customer needs with new and innovative products and services.

Q. How did the Company integrate learnings from its AMF pilot programs in Worcester, Massachusetts and Clifton Park, New York to the Customer Engagement Plan?

A. The Customer Engagement Plan leverages lessons learned and best practices from the Company's affiliates' experiences in their jurisdictions while focusing on Rhode Island customers and what is most useful for them. The Company has incorporated key customer engagement recommendations from the Worcester pilot and Clifton Park demonstration program into the Customer Engagement Plan, including: using a phased approach; ensuring early development of customer engagement tools; providing customer data access and end-use automation technology; implementing personalized insights and outreach; following an opt-out design; leveraging recurring customer feedback surveys; and promoting the program through local events.

Q. Can customers opt out of the AMF program?

A. Yes. During all phases of deployment, customers will have the opportunity to decline receipt of a new advanced meter. Customers will also have the option to receive an advanced meter but opt out of future participation in TVR. Customers will be given advanced notice, via mail and email, of plans to install AMF meters and of the opportunity—and procedure to be followed—to opt out of the AMF metering program. Processes and resources will be in place to support customers who are considering or have decided to opt out. All customers, including those who opt out, will retain the right to purchase energy from an NPP. More detail on how customers can opt out are included in Section 3.4 of the Customer Engagement Plan.

Q. What type of training or resources will Company employees receive to prepare for and ensure a successful AMF deployment?

A. The Company's employees are key ambassadors and vital to a successful deployment as many live in the Company's service territory. The Company will educate employees, including customer service representatives, field workers, customer and community managers, commercial and industrial (C&I) account managers, corporate communications, regulatory team members, and senior management early and often on the entire AMF program through a variety of channels, including employee forums, webinars, learning platforms, email outreach, senior management-led presentations and discussions, and other general communication methods utilized for critical Company updates. More detail regarding employee training is set forth in Section 3.5 of the Customer Engagement Plan, Attachment A to the Updated AMF Business Case.

Q. Will there be any local Company resources available on-the-ground to address customer questions or concerns?

A. Yes, as part of the Customer Engagement Plan the Company plans to do the following:

- Leverage local resources such as Customer and Community Managers or Account Managers to provide support in conjunction with community leaders;
- Utilize the existing Rhode Island Energy Innovation Hub; and
- Attend local community events.

These local resources will be knowledgeable about AMF and able to answer questions and address customer concerns. They will also have access to additional information such as fliers, Frequently Asked Questions, Fact Sheets, a "Getting Started Guide" and more that can be provided to customers.

Q. How does the CEMP enhance customer engagement?

A. The CEMP is a critical component of this Customer Engagement Plan. It builds on the work happening today by enhancing customer-facing initiatives with AMF data. It will serve as an integrated hub of energy data, insights, and actions available to all customers. The CEMP will allow customers to access accurate and personalized energy usage information, as well as various choices and options to enroll in Company and third-party programs and services that can leverage the more granular data provided by AMF meters. The platform is designed to put the customer needs first and allow for quick iterations and adjustments based on user behavior or Company interactions, coordinated with other customer experience improvements. Some CEMP components, such as monthly energy summaries with average usage in smaller increments, could also be layered into non-digital communications like the customer bill or bill insert. The platform will be customers' new touchpoint to access their energy data and will support overall customer engagement with AMF.

For example, residential customers can use the CEMP to access their bill and how much energy they have used, to live-chat with a customer service representative, look into their energy history over time, set high bill alerts, and receive information on energy savings programs, tips, budget plans, and third-party services to help them save on their bills.

Likewise, C&I customers will be able to use the CEMP to have better insights and tools in one place. It will also support a portfolio view of facilities along with other tools geared specifically for C&I customers. Through the CEMP, C&I customers will have access to detailed data visualization and analytical tools on consumption data, energy use intensity benchmarking by building, personalized recommendations, the ability to contact an account representative, and more.

Q. How will the Company reach income-eligible customers regarding AMF?

A. The Company is committed to ensuring that all customers receive clear communications about the benefits of smart meters and new pricing plans. The Company plans to leverage its existing communication channels to ensure multi-faceted smart meter communications efforts that will meet the customer wherever located. These channels include direct marketing, such as postcards, emails, bill inserts, on-bill messages, outbound phone calls, and social media posts; media advertising on bus sides, shelters, and posters in communities; community partnerships; Company Consumer Advocates; and personalized call center software.

IX. Data Governance

Q. How does the Company propose to address data privacy, security, and protection?

A. In accordance with Article II, Section C.16 of the Amended Settlement Agreement, the Company has created a Data Governance and Management Plan (referred to as the Data Governance Plan) regarding data privacy, access, security, and protection. The Data Governance Plan is included with the Updated AMF Business Case as Attachment B.

Q. Does the Company's Data Governance Plan align with the terms of the ASA?

A. Yes. The ASA requires,

> "[a] Data Governance Plan regarding timely customer, NPP, and third-party access to system and customer data, (e.g., elements may include, but

are not limited to, customer assigned peak load contribution, energy and capacity loss factors, interval usage, or other information needed for efficient wholesale and retail market participation) in place and bill quality customer data (e.g., elements may include, but are not limited to, electric usage in kilowatt-hours containing both 'register reads' and 'interval reads') with the proper privacy and security protections."[12]

The Data Governance Plan covers two broad categories of energy data: customer energy usage data and system data. Customer energy usage data is defined to include a customer's electric usage as recorded at the meter in kilowatt-hours. System data is defined to include grid-facing information, such as planning documents that address grid impacts, load-flow models, DER forecasting, and voltage information. Customer data will be accessible by customers, Company employees, and customer-authorized third-parties. System data will be accessible by Company employees, and by DER providers and other third-parties through the Company's existing web-based System Data Portal.

As the Company builds out the detailed requirements for the deployment of AMF and the CEMP, the Company expects to collect the following customer data: read date and days; read type; total kilowatt hours; delivery charges; supply charges; late payment charges;

[12] Article II, Section C.16.b.iv.

total charges; metered peak kilowatts; metered on-peak kilowatts; bill peak kilowatts; bill on-peak kilowatts; TOU off-peak kilowatt hours; reactive power; and load factor.

Q. How will customers access their energy usage data?

A. As mentioned, customers can access their energy usage data through the CEMP, which will be designed so that customers can access this information directly. In addition, customers will be able to access their real-time energy usage data by utilizing the HAN.

Q. How can customers share their energy usage data with third-parties?

A. Customers can choose to share their energy usage and billing data with authorized third-parties through Green Button Connect. Once a customer has authorized a third-party to have access to their data, Green Button Connect facilitates computer-to-computer communication and provides a standardized protocol to provide the third-parties with access. With Green Button Connect, customers can automate the process and securely authorize the Company and designated third-parties to send and receive data on their behalf. This functionality will be developed as a key feature of the CEMP.

Q. How is customer and system data protected?

A. The Company takes customer and system data seriously and is committed to protecting all types of data generated by customer and system operations. Providing access to this data requires the Company to secure, protect, and manage the information.

The Company has developed a comprehensive, integrated data privacy framework comprised of policies, standards, guidelines and statements designed to ensure compliance with privacy and information security obligations while keeping customer and system interests in mind. The data privacy framework is comprised of three key components: i) a commitment to core data-privacy principles; ii) regular assessments of the Company's performance in accordance with the principles; and iii) constant vigilance. The Company's three-tiered approach tracks across people, process, and technology:

- Setting forth policies and standards intended to ensure the Company works to common security objectives by regularly updating privacy and security guidance (including incident management and reporting) for those with legitimate business needs to access customer data;
- Addressing privacy throughout the data lifecycle, working to prevent accidental misuse/loss/exposure of information; and
- Ensuring cybersecurity controls are implemented, information risks are understood, and technologies are selected to keep pace with threats.

In addition, the data privacy framework addresses legal and regulatory requirements, privacy and identity theft vulnerabilities, incorporated accountabilities, business practices and technical and operational controls to effectively manage data privacy risks. Details on the data privacy framework are included in Section 5 of the Data Governance Plan attached to the Updated AMF Business Case.

Q. Please describe the Company's proposal for a Data Use Case Evaluation Framework.

A. As AMF is deployed, bringing with it new systems and technologies, the Company believes a data use case evaluation framework will be needed. Such a framework will allow further opportunities to discuss, explore, pilot, test, and create new data use cases; understand and ensure that they can generate value for customers and the distribution system; and maintain a consistent approach to data access principles, as well as privacy and cybersecurity requirements. To this end, the Company is proposing that a formalized framework be developed through a comprehensive collaboration process with the PST Advisory Group and interested third-parties. Section 4 of the Data Governance Plan discusses the proposed criteria that the Company envisions as key to this new framework.

X. Metrics and Performance Incentive Mechanisms

Q. Did the Company consider the role of Performance Incentive Mechanisms in the Updated AMF Business Case?

A. Yes. During the PST Advisory Group process and PUC technical sessions, stakeholders raised concerns regarding the realization of the full suite of benefits from AMF. The Company recognizes that the benefit realization is essential to customers, regulators, and stakeholders; therefore, the Company is committed to enabling and delivering the benefits identified in the Updated AMF Business Case. Toward this end, the Company is proposing an incentive structure that will directly provide 80 percent of the Non-OMS

Avoided O&M benefit to customers through an adjustment to the revenue requirements in the first rate period following AMF approval. With this commitment, customers are guaranteed to realize benefits and a reduction in bill impacts earlier than they otherwise would. Traditionally, such operational savings would not be reflected until they are captured in base distribution rates resulting from a future rate case proceeding. The commitment also provides an incentive for the Company to ensure the benefits are delivered in a timely manner, as failing to achieve the benefits, which are included as a reduction to the revenue requirement, will result in the Company's expenditures exceeding its cost recovery.

Q. Please summarize the Company's proposed incentive structure.

A. The Company believes that "delivered" benefits and "enabled" benefits should be considered separately in developing an incentive framework. The Updated AMF Business Case classifies benefits into the following categories that reflect the levels of certainty of benefit achievement: i) Non-OMS Avoided O&M Costs, ii) Avoided Outage Management System (OMS) Costs, iii) Avoided AMR Costs, iv) VVO Benefits, v) Non-VVO Customer Benefits, and vi) Societal Benefits. The Company characterizes the Non-OMS Avoided O&M Costs, VVO Benefits, Avoided AMR Costs, and Avoided OMS Costs as "delivered" benefits because they will be achieved through actions the Company takes to successfully deploy AMF (i.e., actions within the Company's control). Savings of the categories within delivered benefits manifest in different ways. Non-OMS

Avoided O&M Costs are delivered benefits which impact the Company's bottom line. VVO Benefits are pass-through benefits to customers, though they require no customer action. Avoided AMR Costs and Avoided OMS Costs are based on estimated costs that would be required to replace AMR assets or that would otherwise be incurred for operational requirements that would be incurred without AMF.

On the other hand, "enabled" benefits are those where the outcome is only partially controlled by the Company. Such benefits rely on a combination of customer awareness and action in response to the new technology and the Company's outreach and education efforts. Non-VVO Customer Benefits and Societal benefits are enabled by AMF and can be influenced by the Company, but ultimately depend on customers changing their behavior. Examples of enabled benefits include customer response to TVR and energy insight/bill alerts.

As mentioned, the Company's proposed benefit guarantee includes a commitment to guaranteeing 80 percent of the Non-OMS Avoided O&M benefits – the benefits from O&M savings not related to outage management – to customers by reflecting these future avoided costs in revenue requirements in the early years of the program before they would otherwise be realized by customers. Table D-1 in the Metrics and Performance Incentive Measures Roadmap attached to the Updated AMF Business Case illustrates how these savings would be provided to customers in electric revenue requirements under a multi-year rate plan scenario.

Q. How does the Company plan to develop performance incentive proposals relevant to enabled AMF customer benefits?

A. The Company believes that the development specific performance incentive proposals for enabled AMF customer benefits should be considered separately from that of delivered benefits. To that end, the Company proposes to work with stakeholders to develop and propose performance incentive mechanisms in subsequent proceedings, with an expectation that these incentives will focus on key outcomes directly tied to customer and societal benefits, as well as new use cases. This effort will require further consideration of the existing landscape for performance incentives. The Company believes that Docket No. 4943 provides a valuable opportunity to advance the discussion of performance incentives more generally, and as they may specifically relate to AMF.

Q. Is the Company proposing any other metrics in the Updated AMF Business Case?

A. Yes, the Company proposes a set of tracking metrics spanning both benefit categories (i.e., delivered and enabled) to demonstrate how the Company is progressing in the delivery of AMF program elements, including core benefits. AMF will enable and support both customer and operational benefits beginning in year three of the AMF program as meters are deployed. The Company is proposing to report on performance in metrics across the following broad categories, which align with the most critical elements and drivers of the overall Updated AMF Business Case:

- Cost Efficiency and Program Implementation: metrics focused on progress related to deployment and program cost efficiency;
- Customer Focused: customer engagement metrics that target key drivers of enabled customer benefits;
- Operations: metrics targeting drivers of operational benefits; and
- Third-Party Engagement: metrics focused on progress to enable and encourage the access and participation of third parties, such as NPPs. Attachment D discusses these metrics in more detail.

XI. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes.

Updated AMF Business Case and Appendices

Schedule KPK/SL-1

Table of Contents

1. Executive Summary

National Grid[1] provides this Updated AMF Business Case in support of its proposal to deploy advanced metering functionality (AMF)[2] across its service territory. The Company's proposal represents a once-in-a-generation opportunity to drive approximately $533 million[3] in benefits on a 20-year net present value (NPV) basis for customers, the electric system, and the environment through a $224 million[4] (20-year NPV) investment in smart meter technology. With the current fleet of automated meter reading (AMR) meters nearing the end of their useful design life, the Company believes now is the time to deploy this new technology and empower customers to take control of their energy usage.

As set forth in this Updated AMF Business Case, the Company has a compelling need to replace its aging metering assets. With input from the Power Sector Transformation (PST) Advisory Group's AMF and Grid Modernization Plan (GMP) Subcommittee (Subcommittee), the Company and stakeholders worked collaboratively over the last two years to understand unmet customer, system, and environmental needs. Together, they considered potential solutions to address those needs, analyzed the solutions, and refined the AMF proposal in a way that drives value for Rhode Island. This business case is the culmination of that extensive effort.

1.1. <u>The Company needs to replace its aging AMR meter infrastructure.</u>

National Grid's AMR meter replacement need is driven by the convergence of three factors:

1) Evolving customer expectations;
2) The operational reality that the current meter fleet is reaching the end of its design life; and
3) Ambitious clean energy goals that require a modern distribution system to achieve.

[1] The Narragansett Electric Company d/b/a National Grid (referred to herein as National Grid or the Company).

[2] AMF refers to the functionality provided by advanced meters, also referred to as smart meters, while Advanced Metering Infrastructure (AMI) refers to an equipment and systems solution that makes smart metering possible. AMF is used universally throughout this filing to refer to smart meters, with the only exception being that AMI is used to refer to smart metering in New York, where the Public Service Commission uses this specific language.

[3] $533 million in benefits represents the opt-out time-varying rate (TVR) scenario and the midpoint between high and low customer response cases. The midpoint for the opt-in TVR scenario benefits is $416 million (20-year NPV).

[4] The $224 million of AMF costs represents the midpoint of the opt-out TVR scenario and assumes a Rhode Island-New York joint deployment scenario using the same AMF solution and on a schedule that maximizes multi-jurisdictional cost synergies. The midpoint for the opt-in TVR scenario costs is $218 million (20-year NPV). The Company uses the joint deployment scenario throughout this Updated AMF Business Case in recognition of the New York Public Service Commission's (NYPSC) approval of the Company's affiliate's AMI proposal. *See* Order Authorizing Implementation of Advanced Metering Infrastructure with Modifications, NYPSC Case Nos. 17-E-0238 and 17-G-0239 at 52-53 (November 20, 2020) [hereinafter NY AMI Order].

From an operational perspective, the Company's meter fleet largely consists of electromechanical meters retrofitted with an encoder receiver transmitter (ERT) that provides AMR functionality,[5] as well as solid-state electric AMR meters with integrated communication capability. The design life of the electromechanical meters is 30 years, while the ERT and solid-state meters have design lives of approximately 20 years. The Company retrofitted the electromechanical meters with ERTs beginning in 2000, meaning they started reaching the end of their 20-year design life this year. Likewise, the Company began purchasing and installing solid-state meters in 2003.

To ensure it can meet its regulatory obligations, the Company must proactively address this metering need by replacing the existing meters with either like-kind AMR technology or with AMF. In this way, a significant portion of the metering costs are unavoidable (i.e., the current meters must be replaced regardless of the metering solution); meaning there is no "do-nothing" scenario. Limiting this analysis to the costs, however, ignores the fact that re-installing AMR meters would deliver almost none of the AMF-associated benefits.

Indeed, the enhanced functionalities enabled by AMF meters ad compared to the limited capabilities of the current AMR meters is a key component of taking meaningful action to meet customer expectations and deliver on shared clean energy goals. AMR technology does not provide energy usage data with the granularity and frequency that makes it useful for delivering energy insights or personalized energy efficiency (EE) and demand response (DR) to customers. Moreover, AMR meters with triple ERT technology only support the most basic of time-varying rate (TVR) structures – an important tool for integrating additional renewable generation, facilitating beneficial electrification (e.g., electric vehicles (EVs) and electric heat pumps), or reducing peak load. AMR meters also lack the two-way communication capabilities that enable remote connections, remote TVR configurations, remote meter investigations, and outage management enhancements. This inability to remotely communicate with AMR meters impacts customer expectations, as well as the environmental benefits achieved from reduced truck rolls.

Taken together, the three factors (meeting customer expectations, system/operational requirements, and achieving clean energy goals) establish a compelling need for an investment in new metering technology that can deliver the functionalities expected in a modernized grid.

[5] AMR metering functionality allows the Company to gather monthly meter readings with vehicles that drive past the meters and pull the energy usage data using a short-range radio frequency (RF).

1.2. Identifying a Solution that Cost Effectively Meets the Demonstrated Need

In November 2017, the Company submitted an application for approval of changes in electric and gas base distribution rates in Docket. No. 4770,[6] along with a PST Vision and Implementation Plan (PST Plan) in Docket. No 4780.[7] The PST Plan proposed a suite of investments, including state-wide deployment of AMF, that would address Rhode Island's metering need and align the Company's energy infrastructure with the state's clean energy policy objectives, consistent with the Rhode Island Public Utilities Commission's (PUC or the Commission) Report and Order in Docket No. 4600[8] and the PUC's Guidance on Goals, Principles and Values for Matters Involving the Narragansett Electric Company d/b/a National Grid (Docket 4600 Guidance Document), regarding the changing electric distribution system.[9]

On August 16, 2018, the Company, the Division of Public Utilities and Carriers (Division), the Rhode Island Office of Energy Resources (OER), along with the other intervening parties filed an Amended Settlement Agreement[10] (ASA) that resolved all disputed issues in both dockets, which the PUC approved on August 24, 2018.

The ASA included an initial, limited set of grid modernization investments as part of a three-year rate case agreement or multi-year rate plan (MRP), and further required the Company to file a comprehensive GMP and Updated AMF Business Case, which describes how each integrates with the other. In addition, the PUC identified twenty-three elements for the Company to address in this Updated AMF Business Case, including a comprehensive benefit-cost analysis (BCA) that fully incorporates the Benefit-Cost Framework adopted by the PUC in Docket No. 4600 (Docket 4600 Framework).[11]

The ASA also required the Company to engage with stakeholders via a newly created PST Advisory Group or relevant subcommittee to develop the Updated AMF Business Case and GMP. Through the PST Advisory Group, the Company formed a GMP and AMF Subcommittee

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[6] *See The Narragansett Elec. Co. d/b/a National Grid, Application for Approval of a Change in Elec.and Gas Base Distribution Rates,* Docket No. 4770 (November 27, 2017).

[7] *See The Narragansett Elec. Co. d/b/a National Grid, Proposed Power Sector Transformation Vision and Implementation Plan,* Docket No. 4780 (November 28, 2017).

[8] *See Investigation Into the Changing Electric Distrib. Sys. and the Modernization of Rates In Light of the Changing Distrib. Sys.,* Docket No. 4600, Report and Order No. 22851 (July 31, 2017).

[9] *See Pub. Util. Comm'n Guidance on Goals, Principles and Values for Matters Involving the Narragansett Elec. Co. d/b/a National Grid,* Docket 4600-A (October 27, 2017) (providing "direction on how the PUC will apply the principles set forth in R.I. Gen. Laws §39-26.6-24(b).").

[10] *See* Amended Settlement Agreement, Docket No. 4770 (approved at Open Meeting on August 24, 2018), http://www.ripuc.ri.gov/eventsactions/docket/4770-4780-NGrid-Compliance%20Filing%20Book%201%20-%20August%2016,%202018.pdf.

[11] *See* Report and Order No. 22851 at 23, 29.

that launched in October 2018. The Subcommittee has engaged with the Company over the course of numerous meetings between October 2018 and September 2020. Through that collaboration, the Subcommittee has provided valuable input to the development of the GMP and the Updated AMF Business Case. Details about this collaboration can be found in Section 2.1, below.

Throughout the process for identifying a solution to the metering need, the Company has relied on the following set of grid modernization objectives that take steps toward achieving the Docket 4600 goals:

1) Give customers more energy choices and information by:
   - Providing more information about energy use and energy choices, including personalized insights and actions based on more granular usage data;
   - Enabling connections and data sharing with third parties;
   - Automating outage notifications; and
   - Providing enhanced energy management capabilities through a customer portal.

2) Ensure reliable, safe, clean, and affordable energy to Rhode Island customers over the long term by aligning customer energy costs with their impact on the grid through more effective load management programs and TVR.

3) Build a flexible grid to integrate more clean energy generation by:
   - Enabling higher penetration of distributed energy resources (DERs) into the grid;
   - Improving grid planning and operations capabilities;
   - Providing granular, real-time values to allow for improved load and DER forecasts; and
   - Supporting DER optimization through more granular data and control at the customer level.

Guided by these objectives, the Company implemented a two-step evaluation process to determine the solutions capable of addressing the demonstrated needs identified above. The first step compared metering technology solution options and complementary customer and grid technologies to determine the functionalities that meet the capability requirements of a modernized grid. The options and functionality assessment reflected input from metering experts and the Subcommittee. The second step of the process considered the relative economics of the viable options identified in step one.

In step one, the Company determined that, while customer and grid-facing technologies can provide a subset of the full-scale AMF functionalities, they are not a viable alternative to an AMF metering solution. Most notably, customer- and grid-facing technologies cannot provide the required revenue-grade billing determinants; as such, alternative technologies result in increased costs without addressing the operational need to replace the AMR meters. In step two, the Company evaluated AMF scenarios (e.g., full-scale and targeted AMF deployment). The Company concluded that targeted AMF deployment, which requires more-costly cellular meters and delivers fewer benefits, is not a cost-effective solution. Instead, full-scale AMF deployment using a mesh communications network is the only fit-for-purpose solution that cost effectively meets the objectives and capabilities for a modernized grid.

As illustrated in Figure 1-1, the proposed AMF technical solution includes four key advanced metering elements: 1) an integrated network of smart electric meters and gas modules capable of capturing customer energy usage data at defined intervals and supporting grid-edge applications; 2) a two-way communications network and related information technology (IT) infrastructure for transmitting the data and control signals that utilize radio frequency (RF) and cellular communications technology; 3) a meter data management system (MDMS), head end system (HES), IT platform, and cybersecurity protections to securely and efficiently collect, validate, store and manage the meter data; and 4) customer systems including billing and a Customer Energy Management Platform (CEMP) to provide energy usage data access, insights, and service offerings to enable customer energy management.

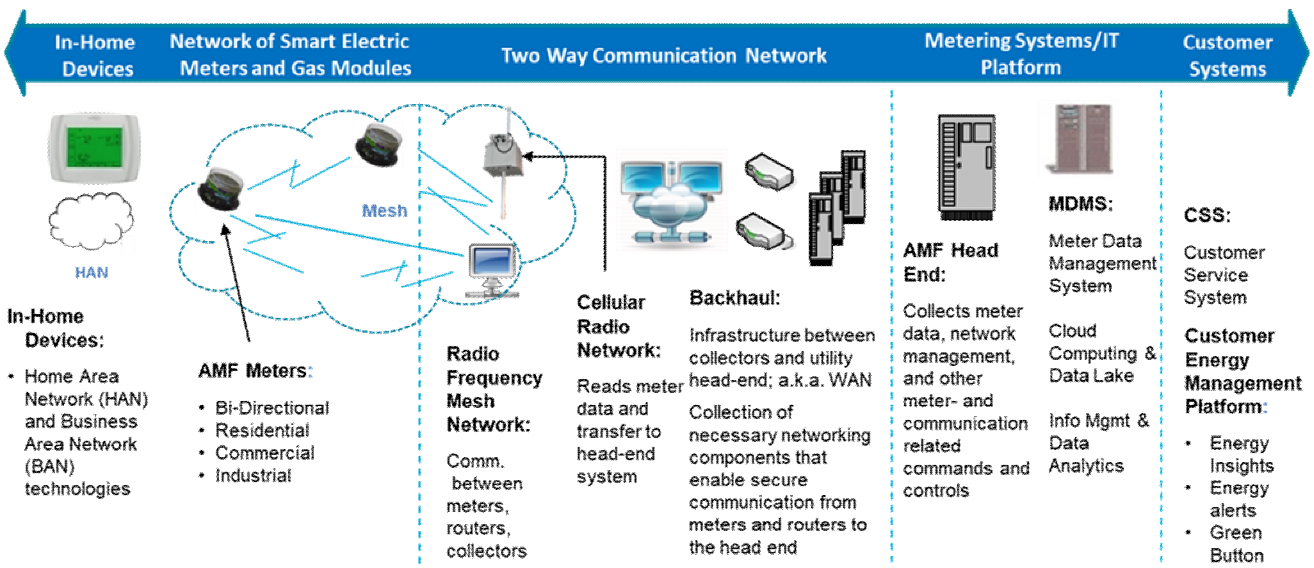

Figure 1-1: AMF Technology Elements

To implement AMF the Company proposes a managed ramp-up for resource onboarding, contract execution, and sanctioning, leading to a three-and-one-half year AMF deployment program as shown in Figure 1-2.

- Phase 1, which covers the first two years following regulatory approval and the managed ramp up, will address detailed design, additional procurement activities, and the installation and upgrade of the back-office systems.

- Phase 2, starting in the last quarter of phase one and running for approximately one year, involves the deployment of the mesh communications network.

- Phase 3, which would commence after the completion of phase one and run in conjunction with the remainder of phase 2, involves the deployment of electric meters over an 18-month period and the installation of AMF-compatible gas modules as part of normal course of business in AMF-enabled areas. As further illustrated by Figure 1-2, the Company also plans to employ a robust Customer Engagement Plan (CEP) with activities occurring before, during, and after meter deployment. Also shown is an estimated timeline for the development, proposal, and launch of TVR.

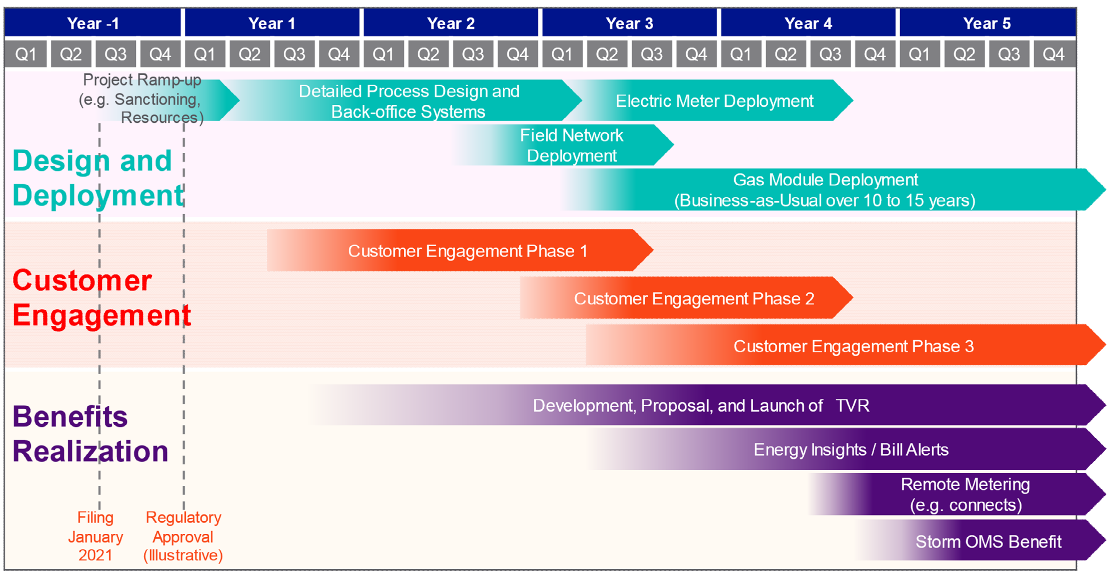

Figure 1-2: Illustrative Rhode Island AMF deployment timeline

1.3. Value of AMF for Customers, the System, and the Environment

The AMF solution will deliver new functionalities that provide significant benefits to customers, the system, as well as to the environment.

Customer Benefits

- *Enhanced Energy Management* – Enable customers to take control of their energy usage through more effective EE, conservation, and DR programs, along with access to smart-home devices. AMF improves the efficacy of EE and DR programs by providing more granular data to customers (e.g., detailed billed energy use and in-home displays).

- *Third-Party Programs and Offerings* – Animate the market for third-parties to drive innovation and provide additional value to customers, while encouraging industry participants to enter the market with new customer offerings.

- *Customer Service Enhancements* **–** Notifications about changes to consumption patterns mid-month that give customers an opportunity to act before the end of the billing cycle, remote connect and disconnect for electric service, and enhanced outage management capabilities.

- *Savings on EV Charging Costs* – Using TVR that incentivize customers to shift vehicle charging to off-peak times.

- *Reduce Customer Energy Costs* – Shifting load[12] in response to energy insights, AMF-enabled TVR, and personalized load management programs.

System Benefits

- *Situational Awareness/Forecasting* – AMF, in combination with other GMP investments, provides granular, real-time values that can be aligned with other system data to create actual loading and voltage profiles at all points along a feeder. This complete data set can be modeled directly and more detailed load and DER forecasts can be developed for planning needs.

- *Load Shift* – Reduce customer delivery costs by avoiding traditional distribution infrastructure investments due to the ability to shift load using AMF-enabled TVR and more effective customer load management programs.

- *Voltage Conservation* **–** Enhancing the ability for voltage conservation to reduce demand and energy use through conservation voltage reduction (CVR). The advanced Volt-VAR Optimization (VVO) control schemes coordinate multiple voltage regulating device of a feeder to achieve optimal CVR performance. An incremental 1% improvement is expected to be achieved by integrating granular AMF voltage data into the VVO control schemes.

- *DER Optimization* – AMF supports DER optimization by providing the interval energy and voltage data at the customer level required for verification and settlement of DER services provided to or received from the grid. AMF also enables the exchange of information and/or control with in-home, business, or grid connected DER technologies.

[12] Shifting energy consumption between time periods to reduce energy costs and/or keep system parameters within predetermined limits.

- *Automated Notification* – AMF meter outage information integration with the Company's outage management system (OMS) and processes will improve customer communications and restoration operations. AMF reports customer outages in near real-time, which provides system outage awareness and allows field personnel to restore power without relying solely on customer calls and substation monitoring. AMF can also verify whether power has been restored to all meters.

Environmental Benefits

- *Reduce Harmful Emissions* – By helping customers to reduce energy usage, and reducing truck rolls through remote operations and meter investigations, and facilitating the interconnection of additional DERs, including distributed generation (DG) and energy storage, AMF will facilitate further CO2 emission reductions.

To quantify and evaluate the benefits, the Company developed the AMF BCA consistent with the Docket 4600 Framework. In doing so, the Company incorporated several sensitivities into the analysis to account for uncertainties that lie outside the Company's control (e.g., customer participation in TVR via a rate design that is either opt-in or opt-out, as well as high and low customer responses to price signals and usage alerts).[13] The "Base Case" scenario, which is referenced throughout this Updated AMF Business Case, assumes an opt-out TVR rate design, and the midpoint between high and low customer response to price signals and usage alerts.

With these assumptions, the BCA demonstrates that full-scale AMF deployment can yield benefit-cost ratios of 2.38 (opt-out) and 1.91 (opt-in) based on estimated total benefits of approximately $533 million (20-year NPV for the opt-out scenario) and $416 million (20-year NPV for the opt-in scenario), and corresponding costs of approximately $224 million (20-year NPV for the opt-out scenario) and $218 million (20-year NPV for the opt-in scenario). This approach includes multi-jurisdictional cost synergies that the Company believes can be achieved through co-deployment with its upstate New York affiliate. If approved by the PUC, the Company will include these expenditures in the revised base distribution rates consistent with the ASA.

The BCA accompanying this Updated AMF Business Case differs from that presented in the Company's 2017 PST Plan in several respects. Using the Subcommittee feedback and responses to the Company's Request for Solution (RFS), the BCA includes updated costs and key benefit forecasts. The Company also refined some of its calculation methodology from the PST Plan. Importantly, the expanded application of the Docket 4600 Framework has also resulted in a more complete list of benefits. The waterfall chart in Figure 1-3 uses the opt-out TVR assumptions to compare the benefit elements of this filing to those used previously.

[13] Section 8.2.1 describes the different scenarios in greater detail.

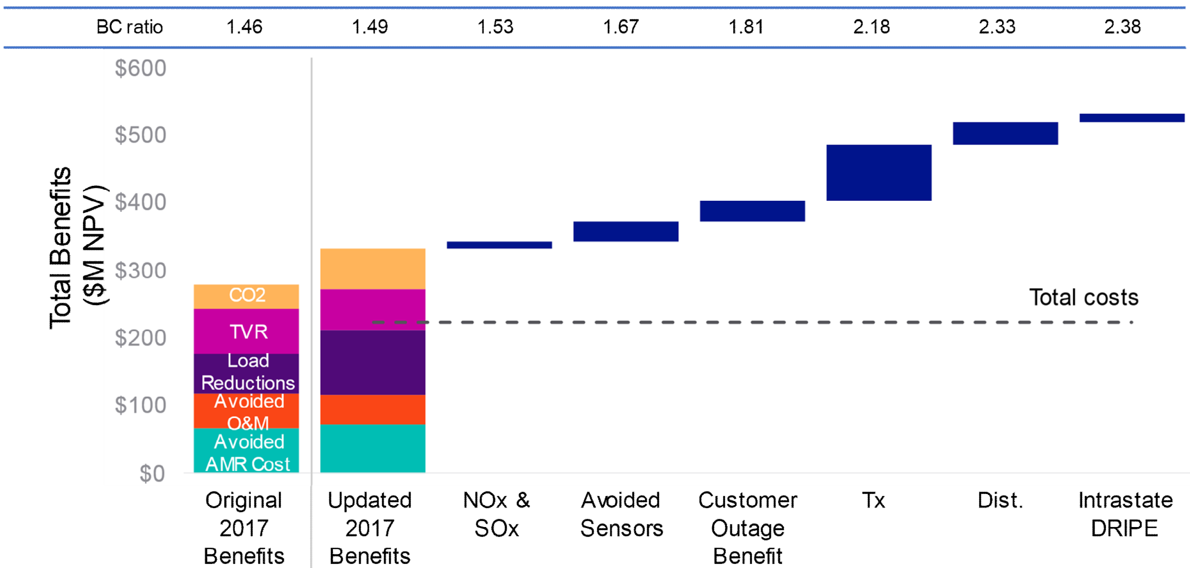

Figure 1-3: <u>Opt-out</u> benefits broken out by category. Categories in the stacked bars are categories that were included in the 2017 filing BCA. Categories in the waterfall are new to the BCA in this filing. The 2017 BCA ratio is based on the 2017 costs, which do not appear in the figure.

The Company notes that for the opt-out TVR design scenario shown in Figure 1-3, the benefit categories added since 2017 to align with the Docket 4600 Framework provide nearly $200 million in benefits. Furthermore, the BCA shows a strong likelihood of program cost-effectiveness, even without strong customer response to TVR and Energy Insights / Bill Alerts.

Because the cost-effectiveness of the AMF investment does not depend on strong customer response to TVR, the Company does not believe possible customer migration to third-party supply creates a significant risk. Indeed, even in a scenario where DER adoption continues at low levels, the BCA indicates AMF will still be a cost-effective investment with less than 5% of customers participating in the TVR program. This level is far below the levels of participation seen in jurisdictions with mature third-party supply markets.

1.4. <u>Accountability through Reporting, Program Management, and Guaranteed Savings</u>

The realization of the AMF benefits that support this Updated AMF Business Case is essential to Rhode Island customers. The success of achieving benefits can be bolstered through effective program reporting and risk management. For the purposes of tracking and reporting AMF implementation costs, the Company proposes filing an AMF Program Report with the PUC on a semi-annual basis. The AMF Program Report will address the status of the AMF deployment, including: 1) a narrative explaining overall AMF implementation status; 2) detail on actual spending relative to the AMF budget; 3) allocations of AMF costs to the Company as appropriate; 4) explanations of variances between budgets and actual spending; and 5) metrics reporting in areas such as program implementation, customer engagement, operations, and third-party engagement as discussed in Attachment D: Metrics and Performance Incentive Measures Roadmap. Once a year, in the AMF Program Report that is filed sixty days after the end of the respective fiscal year, the Company will also include any cost or timeline differences that exceed 10% for the fiscal year and the latest AMF sanction paper authorized during the fiscal year. The Company will also hold semi-annual meetings with the Division and OER to review the AMF Program Report.

The scale, scope, and term of the AMF proposal also requires careful management to ensure customers will recognize the envisioned benefits of the program. The Company believes the AMF proposal and deployment plan include the steps necessary to manage the benefits it can directly influence while also explicitly recognizing certain risks that are beyond its control. The steps are described in detail in various sections of this Updated AMF Business Case and are summarized below to convey the Company's comprehensive management approach.

Solution Management:

- The AMF proposal was developed and evaluated in concert with the broader GMP, which includes a long-term integrated GMP and AMF roadmap evaluated on a benefit-cost basis to ensure the timing and associated costs of the new functionalities are aligned with system and customer needs. The evaluation resulted in the development of a five-year plan in core, enabling functionalities, including AMF, that are common to all future state GMP scenarios evaluated.

- The Company considered alternative metering solutions and compared them to the AMF solution within this Updated AMF Business Case based on relative functionalities and benefits and costs. The results demonstrate that full-scale AMF deployment is the most cost-effective fit-for-purpose solution that also delivers the greatest customer- and grid-facing functionality.

- The procurement process for the AMF solution evaluated functionalities, vendor roadmaps, and solution offerings such as Software-as-a-Service (SaaS), to provide solution flexibility and adaptability to address the risk of technology obsolescence.

Managing Cost Risk and Delivering Benefits:

- The Company has taken multiple actions regarding AMF program cost estimates to establish enhanced cost certainty as compared to the Company's prior filing estimates. Primary to these efforts is cost estimate refinement through the RFS solicitation for major components of the AMF solution including the electric meters, gas modules, field area network (FAN) equipment, back-office systems, and related professional services. The costs of periodic technology refreshes (hardware and software) over the 20-year term of the BCA and non-RFS component cost contingencies have also been factored into the costs. Lastly, the Company has leveraged its experience with past large-scale meter deployments and industry references to refine several cost and benefit categories.

- The Company also developed the comprehensive CEP with input from the Subcommittee to support the achievement of the envisioned customer benefits. The CEP is included as Attachment A.

- As mentioned, the Company also developed a comprehensive BCA consistent with the Docket 4600 Framework that evaluated alternative deployment scenarios and key cost and benefit sensitivities.

- To measure the progress and effectiveness of the Company's planned AMF deployment, the Company developed a roadmap of proposed metrics and performance incentive measures. The roadmap includes a robust set of initial metrics reported on a semi-annual basis, as well as a process and timeline for the development of performance incentives that promote efficiency and effectiveness. The proposed Metrics and Performance Incentives Measures Roadmap is included as Attachment D.

- The Company will also develop a project governance structure to oversee the AMF program and make critical decisions, assure cross functional alignment, and effectively manage implementation.

Finally, the Company proposes to directly provide a portion of Non-OMS Avoided O&M benefits to customers through an upfront adjustment to the revenue requirements. The benefits include reduced operational costs, remote meter capabilities, and reduction of damage claims, as well as pass-through savings from avoided energy costs and avoided AMR meter costs. Committing to deliver 80% of the Non-OMS Avoided O&M benefits in the early years of the project, establishes project accountability to deliver the AMF solution in three ways. First, it enables customers to receive the benefit savings sooner than they would under typical rate procedures, which would require the benefits to first be reflected in the historic test year and incorporated in rates after they are realized. Second, providing this upfront adjustment creates an incentive for the Company to achieve the benefits in accordance with the planned timeline, as failure to do so would mean the Company is under collecting its actual costs. Third, this approach also creates an incentive for the Company to maximize the benefits and deliver them quicker, as savings in excess of the 80% would be retained by the Company until the next rate proceeding.

1.5. Business Case Outline

This Updated AMF Business Case presents the Company's AMF proposal and analysis of the associated costs and benefits over a 20-year period that represents the life expectancy of the proposed AMF solution. The GMP was developed in close coordination with this Updated AMF Business Case and presents the consolidated GMP investment plan and BCA. More detailed information on certain topics appears in the: Customer Engagement Plan (Attachment A), Data Governance and Management Plan (Attachment B), Time-Varying Rates Overview (Attachment C), Metrics and Performance Incentives Measures Roadmap (Attachment D), and the Updated AMF Benefit-Cost Analysis (Attachment E). This Updated AMF Business Case is structured as follows:

- **Section 2: Updated AMF Business Case Approach**
  Presents the Company's approach to the development of this business case, including the Subcommittee workplan and schedule, consideration of best practices in other jurisdictions, and the consideration of TVR within the BCA. It also summarizes how the Company incorporated stakeholder input for the twenty-three AMF components identified in the ASA, and, for convenience, it identifies the section(s) of this business case where each ASA element is addressed.

- **Section 3: Background: The Current State of Metering**
  Provides background on the current state of AMF deployment in the United States, the status of affiliate AMF proposals in New York and Massachusetts, and the Company's current electric and gas meter reading technology in Rhode Island.

- **Section 4: Grid Modernization Roadmap and AMF Integration**
  Describes the GMP objectives, the development of the GMP investment roadmap, and the fundamental role AMF plays as part of the integrated GMP by enabling and delivering both customer- and grid-facing functionalities.

- **Section 5: Metering Technology Solution Screening and Detailed AMF Roadmap**
  Assesses alternative metering solutions to AMF and describes the key design characteristics of the AMF solution that provide flexibility and adaptability to meet future, evolving needs. It also presents a long-term AMF roadmap describing the functionalities that will be implemented in the initial AMF deployment, the functionalities that will be considered in the future, how the functionalities integrate with GMP functionalities, and lastly, the potential to integrate other end-point technologies (e.g., water meters, street lights).

- **Section 6: Consideration of Alternative Business Models**
  Describes new and emerging approaches to the implementation of AMF and how these opportunities have been considered within the Company's AMF proposal.

- **Section 7: Program Implementation**
  Describes the elements of the AMF program including the implementation timeline, meter deployment, customer engagement, program management and the impact on existing customer programs.

- **Section 8: BCA Evaluation Under Docket 4600**
  Presents the AMF BCA approach and results including Docket 4600 alignment, cost contingencies, future state and deployment scenarios, cost-benefit sensitivity analysis, and enabled future benefits.

- **Section 9: Reporting and Risk Management**
  Presents the proposed tracking and reporting of AMF implementation progress and costs, and the steps taken in developing the AMF proposal and deployment plan to manage aspects of the project that are under the Company's direct control. This section also includes a detailed discussion of the proposed Metrics and Performance Incentive Measures Roadmap included as Attachment D.

2. Updated AMF Business Case Approach

The Company has undertaken a thoughtful and thorough approach to developing this Updated AMF Business Case. The process has included engaging stakeholders through the PST Advisory Group process, targeted deep-dive sessions with the Division and OER, and addressing each of the AMF components identified in the ASA. Also, the Company has crafted an illustrative approach to TVR that supports the BCA, while also providing flexibility for the more thorough TVR evaluation that will follow the Updated AMF Business Case filing. The Company has tested its overall approach against the lessons learned from other recent AMF and GMP filings across the country. This section discusses each of these areas and begins to describe how this Updated AMF Business Case is consistent with the PUC's Docket 4600 Guidance Document.

2.1. PST Advisory Group GMP and AMF Subcommittee Engagement

The Company, in partnership with the Division and OER, established the PST Advisory Group in October 2018, and formed the Subcommittee to gather stakeholder input for the development of this Updated AMF Business Case and the GMP. As prescribed by the ASA, the Subcommittee members include representatives with environmental, clean-energy, low-income, community, and business interests, as well as Non-regulated Power Producers (NPPs).[14] Together, stakeholders developed the workplan and schedule, illustrated in Figure 2-1, to foster collaboration and stakeholder feedback on the Company's Updated AMF Business Case and GMP proposals, consistent with the ASA requirements.

[14] *See* Appendix 10.6 for a complete listing of Subcommittee members.

As depicted in Figure 2-1, the Subcommittee met regularly from October 2018 through September 2020. The meetings were sequenced such that the first set of meetings focused on detailed topical discussions of components of this Updated AMF Business Case and requirements of the ASA, such as customer value streams, customer engagement, data privacy, rate design, and application of the Docket 4600 Framework to the BCA. These initial meetings sought feedback and alignment on the approaches being considered, and on the integration of this Updated AMF Business Case with the GMP. Following these meetings, a set of milestone meetings were held to review the Updated AMF Business Case, which included the updated BCA and methodology, as well as associated revenue requirements, bill impacts, and cost allocation methodology.

In addition to the scheduled meetings, the PST Advisory Group participated in a workshop at the PUC on April 9, 2019. On April 23, 2019, the PUC held an open meeting to discuss and provide feedback on the workshop. On November 5, 2019 and September 24, 2020, the Company also participated in PUC technical sessions to provide a status update on the various work streams, including the work of the Subcommittee. Following the workshop and technical sessions, the Company augmented relevant sections of the Updated AMF Business Case to address the PUC's interest in a holistic AMF/GMP plan that would allow it to: i) understand all the costs associated with achieving benefits listed in the BCA; ii) utilize Performance Incentive Mechanisms (PIMs) to shield customers from risks; iii) explore the effects of different levels of electrification adoption; and iv) provide information on any potential health risks connected to advanced metering technology. In addition, the Company added additional milestone meetings and extended the filing date to allow for further stakeholder input on the Updated AMF Business Case and its integration with the GMP, and to address stakeholder concerns including, the impact of third-party supply on AMF benefits, the impact of increased access to remote net metering on AMF benefits, and the scope of the Data Governance and Management Plan (Data Governance Plan).

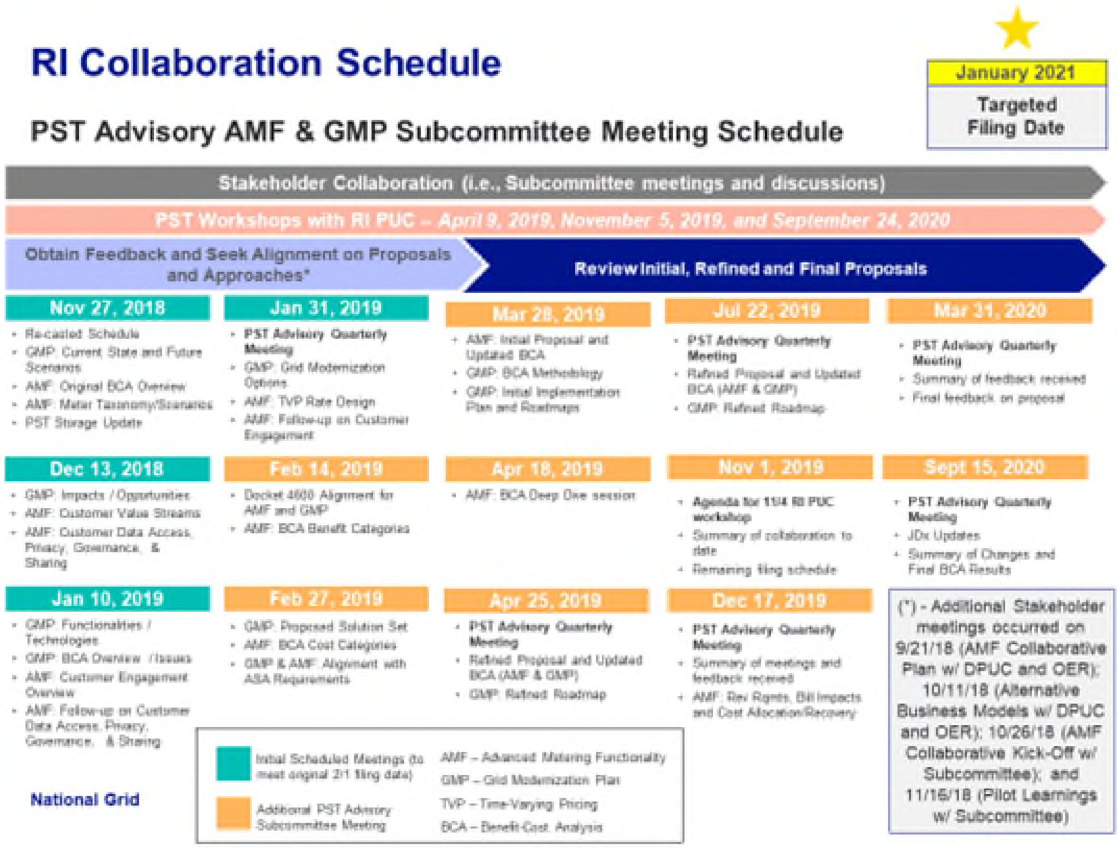

Figure 2-1: PST Subcommittee Workplan and Schedule

The Company has addressed each element required by Article II, Section C.16.iv of the ASA. Additionally, the Company has incorporated other areas that have arisen through the PST Advisory Group process and has documented stakeholder input relevant to each item, as shown in Table 2-1 below. The first column of Table 2-1 lists the ASA elements and the second column Table 2-1 summarizes the results of the stakeholder engagement process relative to each element. The third column identifies the section(s) of this Updated AMF Business Case where the Company has addressed each of these elements.

The stakeholder engagement descriptors may be in the form of feedback (input or directional), alignment, or an agreement depending on what the content represents:

- "Feedback" indicates a preference demonstrated by one or more stakeholders.
- "Alignment" indicates a response of stakeholders to the Company's initial proposed approach.
- "Agreement" indicates a more thorough discussion held by the Subcommittee on how to approach a given element in this Updated AMF Business Case, but does not necessarily reflect full consensus by all stakeholders on a particular issue.

Table 2-1: A complete list of AMF-Related Requirements from the ASA Addressed in this Updated AMF Business Case

Updated AMF Business Case Requirements per the ASA	Subcommittee Feedback / Alignment / Agreement	Business Case Section(s)
A refined and updated AMF business plan, benefit-cost analysis (BCA), and a detailed CEP	Agreement to share drafts of this Updated AMF Business Case and CEP for Subcommittee comment in advance of the filing. Agreement to explicitly identify feedback areas in the filing.	BCA: Section 8 Attachment E CEP: Section 7.2, Attachment A
An updated AMF deployment schedule with a BCA (using the Societal Cost Test) for different meter deployment periods	Agreement that the deployment period should align with the proposed AMI[15] deployment period in New York to fully leverage synergies of co-deployment. Agreement that the deployment period should align with AMR lifetime replacement cycle to avoid stranding assets.	Section 7.1 Section 8.4.1
Revenue requirement for AMF deployment	Alignment that the revenue requirement should include treatment of unrecovered AMR costs. Agreement that the proper revenue requirement counterfactual should include AMR reinvestment and additional grid sensors.	Revenue Requirements and Pricing Panel Testimony

[15] The NYPSC refers to AMF as advanced metering infrastructure (AMI). As such, the Company uses AMI when referring to its affiliate's New York filing. Likewise, the Massachusetts Department of Public Utilities (DPU) distinguishes between AMF and AMI; noting that "[a]dvanced metering functionality includes a broader range of technology than just [AMI] or 'smart meters.'" *Investigation by the Dep't of Pub. Util. on its own Motion into the Modernization of the Elec. Grid – Phase II*, Docket D.P.U. 20-69 [hereinafter MA Grid Mod Phase II Investigation].

Updated AMF Business Case Requirements per the ASA	Subcommittee Feedback / Alignment / Agreement	Business Case Section(s)
Deployment proposals, a proposal for cost recovery of AMF, and any activities associated with implementation of AMF	Feedback on importance of cost recovery and deployment proposals	Revenue Requirements and Pricing Panel Testimony
A proposal to allocate AMF costs among rate classifications	Feedback that it is important to see impacts by rate class (e.g., largest C&I customers who already have interval metering in place). Feedback to give additional thought to temporal alignment of benefits realization with cost allocation for gas customers.	Revenue Requirements and Pricing Panel Testimony
Assumptions upon which a proposal to develop time-varying rates will be based	Agreement that filing will not request approval of a TVR design, but will discuss a spectrum of potential TVR designs. Agreement that, for the purposes of developing this business case, the Company will present benefits from an illustrative time-of-use (TOU)/critical peak pricing (CPP) supply rate, with other rate designs discussed qualitatively and with quantitative sensitivities around response to the TVR design. Agreement that cost-reflective TVR on delivery rates as well as supply maximizes ability to send efficient price signals (though views on method diverge).	Section 2.2, Section 8.2.1, Appendix 10.4, Attachment C
A Data Governance Plan regarding timely customer, NPP, and third-party access to system and customer data, … in place and billing quality customer data … with the proper privacy and security protections	Feedback that Company should, in addition to explaining current and future data governance practices, address considerations in data governance that are unique to AMF. Agreement to have dedicated attachment within the filing in addition to some elements appearing in the CEP.	Section 7.2.4, Attachment B

Updated AMF Business Case Requirements per the ASA	Subcommittee Feedback / Alignment / Agreement	Business Case Section(s)
Updated costs for AMF deployment based on information gained from a procurement effort	Agreement to incorporate input from the procurement process into the BCA.	Section 8.3
Transparent, updated benefit cost analysis that fully incorporates the Docket 4600 Framework	Agreement that every Docket 4600 category will be addressed either quantitatively (to the extent practical) or qualitatively in the filing. Agreement that quantified categories that do not appear in the Company's BCA Base Case will appear in sensitivities.	Section 8
Investigation of alternative business models and ownership models	An assessment prepared for the Company by Accenture (that supports the Company's proposal) was shared with the Subcommittee for feedback. Alignment on the qualitative assessment of alternative technology options.	Section 6 Section 5.1
Analysis of data latency	Feedback that filing should address AMF use cases and latency requirements for each.	Section 5.2
Deployment details	Feedback that gas-only customers should see costs that correspond to the gas module deployment schedule. Feedback that proactive engagement with key community stakeholders before, during, and after meter deployment is vital. Alignment that the CEP needs to address behavioral science and income-eligible customer experience.	Section 7.1 Attachment A
Role of non-regulated power producers, including articles to share customer information and customer engagement	Agreement that NPPs need to hold the customer's data in strict confidence and apply privacy standards. Agreement that Green Button Connect (GBC) functionality will give customers easy ability to share their data. Feedback that NPPs are likely to offer TVR.	Section 8.2.1, Attachment B, Attachment C

Updated AMF Business Case Requirements per the ASA	Subcommittee Feedback / Alignment / Agreement	Business Case Section(s)
Ownership model for assets and telecom	An assessment prepared for the Company by Accenture (that supports the Company's proposal) was shared with the Subcommittee for feedback.	Section 6
Detailed AMF functionalities, how Rhode Island will achieve those functionalities, and a timeline for when those functionalities will be available	Feedback that achieving functionalities is critical, and steps should be taken to track achievement of major functionality milestones over time.	Section 5.3, Attachment D
Identification of the most cost-effective way to achieve the functionalities, and how the functionalities align to the policy objectives	Feedback that proposal should address multiple metering solutions to determine if AMF is the most cost-effective solution to achieve policy objectives.	Section 5.1
Explanation of whether the realization of those functionalities will require additional future work and costs over 20 years	Feedback that the BCA should only include benefits that do not require additional equipment beyond what is explicitly included in cost estimates. Alignment that possible future use cases should be discussed in the filing, in addition to overlap with different dockets, such as EE.	Section 5.2, Section 7.5
Identification of whether the AMF solution would allow for proper net metering according to the tariff	Agreement that Company will address this directly in the filing.	Section 3.3.2
Identification of what functionalities AMF will achieve that are part of the Grid Modernization Plan and which are in addition to the Grid Modernization Plan	Feedback that a list of interrelated functionalities should appear in the filing. Agreement that simultaneous filings make these relationships easier to understand.	Section 4
Identification of which functionalities are dependent on a full-scale roll out instead of a targeted roll out	Alignment that comparison of functionalities and screening comparison of costs/benefits between targeted and full-scale roll outs are required to support an AMF decision.	Section 5.1

Updated AMF Business Case Requirements per the ASA	Subcommittee Feedback / Alignment / Agreement	Business Case Section(s)
Business case based on both a Rhode Island-only (RI-only) scenario and a Rhode Island/New York (RI+NY) scenario	Agreement that both scenarios need to be presented in filing unless New York outcome is known before Rhode Island filing.[16]	Section 8.2.1
A business case based on the length (duration) of meter deployment	Agreement on proposed 18-month meter deployment following 2-year back-office systems and process development phase.	Section 8
Identification of the critically linked parts of grid modernization and AMF	Agreement that AMF is a substantive component of grid modernization. Feedback that a list of interrelated functionalities should appear in the filing.	Section 4

Table 2-1 highlights the value of the stakeholder engagement process by showing how the Company has shared its progress with stakeholders, considered their input, and woven feedback on the ASA components throughout this Updated AMF Business Case.

2.2. Time-Varying Rates (TVR)

The ASA requires that this Updated AMF Business Case include "assumptions upon which a proposal to develop time varying rates will be based"[17] and further provides that "the Company's Updated AMF Business Case and associated Company proposals in relation to time varying rates will be subject to consideration by the PUC in a separate docket, and all interested parties will have an opportunity to participate in any process provided prior to PUC action on the Updated AMF Business Case and proposals contained therein."[18]

There is broad consensus that the Company should transition to TVR, reflected in both customer surveys (*See* Attachment C: Time-Varying Rates Overview) and Subcommittee feedback. In an online survey completed in January 2019 of the Company's customers, 79% of respondents indicated that they were "very interested" or "somewhat interested" in a TVR plan. Likewise, the Company's pilots in other states have demonstrated that customers are responsive to, and are generally supportive of TVR. The Company believes that TVR supports customers' needs and is an important enabler of Rhode Island's future electricity system.

[16] On November 20, 2020, the NYPSC approved the Company's affiliate's AMI proposal. *See* NY AMI Order, *supra* note 4.

[17] Amended Settlement Agreement, Article II, Section C.16.b.iv.

[18] *Id*.

Consistent with the ASA, the Subcommittee concluded that a more thorough and complete record would need to be established as part of a separate docket to develop a definitive TVR design in the future. Accordingly, the Company is not requesting approval of a TVR design in this Updated AMF Business Case, but instead discusses a spectrum of potential TVR designs, including both for supply and delivery rates. The Company will make a TVR proposal in the next suitable future filing prior to the AMF system becoming operational.

For the purposes of estimating TVR benefits in the BCA, the Company presents benefits from an illustrative time-of-use (TOU) critical-peak pricing (CPP) supply rate, with other rate designs discussed qualitatively and with quantitative sensitivities around response to the illustrative TVR design. The rate considered is technology-neutral and designed for the residential class only, so all modeled TVR benefits are brought about by this single design and come only from residential usage. Furthermore, TVR savings modeled do not assume adoption of any additional technology (e.g., in-home displays, smart appliances, etc.), so the savings should be accessible by all customers.

Table 2-2: Consistency of Rates Designs with Rate Design Principles Described in Docket 4600. Circle shading indicates degree of consistency with principle). Note: *VPP* refers to variable peak pricing; *ICAP* refers to installed capacity tag in the forward capacity market; *RTP* refers to real-time pricing

	Principle	Flat Rates	TOU	VPP	CPP	TOU + CPP	TOU + ICAP	RTP + ICAP
1	Ensuring safe, reliable, affordable, and environmentally responsible electricity service today and in the future	●	●	●	●	●	●	●
2	Promoting economic efficiency over the short and long term;	○	◔	◐	◐	◕	◕	●
3	Providing efficient price signals that reflect long-run marginal cost	○	◔	◐	◐	◕	◕	●
4	Appropriately address "externalities" that are not adequately counted in current rate structures	○	◔	◔	◔	◐	◐	◕
5	Empowering consumers to manage their costs	○	◔	◐	◐	◕	◕	●
6	Enabling a fair opportunity for utility cost recovery of prudently incurred costs and revenue stability	●	●	●	●	●	●	●
7	Fair compensation for value and services received and fair compensation for value and benefits delivered	○	◔	◐	◐	◕	◕	●
8a	Being transparent ...	○	◔	◐	◐	◕	◕	●
8b	... understandable to all customers	●	●	◕	◕	◐	◕	●
9	Changes ...implemented with due consideration ... of gradualism, ample time for customers to understand new rates and lessening immediate bill impacts	N/A	◕	◐	◐	◐	◐	◔
10	Providing opportunities to reduce energy burden and address low income and vulnerable customers' needs	○	◔	◐	◐	◕	◕	●
11	Consistent with policy goals such as environmental protection, addressing climate change and the Resilient Rhode Island Act, energy diversity, competition, innovation, power/data security, and least cost procurement	○	◔	◐	◐	◕	◕	●
12	Encourage ... appropriate investments that enable the evolution of the future energy system	○	◔	◐	◐	◕	◕	●

Based on the analysis of different rate structures presented in the Time-Varying Rates Overview (Attachment C) and summarized in Table 2-2, the Company believes the selected energy supply TOU/CPP rate is most consistent with the rate design principles laid out in Docket 4600, striking a balance among economic efficiency, customer empowerment, transparency and understandability, and the principle of gradualism. Additionally, the TOU/CPP supply rate design has been studied in several pilot programs, and, therefore, has more available data on customer response than any other TVR design to support the estimation of customer benefits. This includes the Company's affiliate's experience with the design of its Worcester, Massachusetts Smart Energy Solutions Pilot (Worcester Pilot). More information on the Worcester Pilot is included as part of Appendix 10.8. Table 2-3 shows a list of pilot programs included in a Department of Energy (DOE) study from 2016. As the top two rows reveal, TOU/CPP is the most well-represented pilot rate design.

Plausible benefits estimated from this evidence suggest that a TOU/CPP rate design, or another design that performs at least as well, achieves benefits large enough bolster the cost effectiveness of the AMF proposal. As such, the Company believes the approach to estimating TVR benefits in the BCA establishes a threshold level of customer net benefits that alternative TVR designs should be required to meet in any forthcoming TVR docket. This threshold level of benefits is shown to be above the minimum amount needed to achieve cost-effectiveness of the proposed AMF program.

As Table 2-2 illustrates, the TOU/CPP design is in the middle of the spectrum of potential TVR designs in terms of promoting economic efficiency and empowering consumer energy savings. For example, the modeled TOU/CPP rate does not include changes to delivery rates. The Company believes that, given that electric supply (energy and generation capacity) accounts for nearly half of average customer bills, this category provides the largest opportunity for bill reductions. Stakeholders have also expressed an interest in having a TVR component in the delivery portion of the bill. To that end, the Company anticipates evaluating alternative delivery rate designs for their value in avoiding or delaying distribution infrastructure investments in a future proceeding. Incorporation of changes to delivery rates would enhance the overall benefits from customer response to rates enabled by AMF including customers who opt for third-party supply service that remain subject to the Company's delivery rates.

Details on the TOU/CPP design and customer response to the rate, which, taken together, establish the TVR benefits listed in the BCA, are available in Appendix 10.4.

Table 2-3: ***Pilot programs surveyed and the TVR rate elements of those programs. From DOE,*** **Final Report on Customer Acceptance, Retention, and Response to Time-Based Rates from Consumer Behavior Studies,** ***(2016). Note "CPR" refers to Critical Peak Rebate***

	CEIC	DTE	GMP	LE	MMLD	MP	NVE	OG&E	SMUD	VEC
Rate Treatments										
CPP		●	●		●	●	●	●	●	
TOU Pricing		●		●		●	●	●	●	
VPP								●		●
CPR	●		●							
Utility Abbreviations: Cleveland Electric Illuminating Company (CEIC), DTE Energy (DTE), Green Mountain Power (GMP), Lakeland Electric (LE), Marblehead Municipal Light Department (MMLD), Minnesota Power (MP), NV Energy (NVE), Oklahoma Gas and Electric (OG&E), Sacramento Municipal Utility District (SMUD), Vermont Electric Cooperative (VEC)										

2.2.1. AMF Benefit Attrition Due to Third-Party Service and Remote Net Metering

The Subcommittee and the PUC expressed concern that the benefits associated with AMF could be reduced by the Company serving fewer kWh of supply. This could happen if many customers migrate to third-party supply service, or if many customers install net metered systems that offset their entire site load. The Company, however, believes that neither of these possibilities will erode the AMF benefits significantly nor deter the Company from the commitment to offering TVR.

In the case of migration to third-party supply, evidence from jurisdictions with mature third-party supplier markets suggests the percentage of customers on TVR will not drop below that assumed in the Company's opt-in case presented in Section 8 (more detail on this appears in Section 8.2.1). Given the likelihood that third parties will offer TVR to customers if advanced metering is installed, the Company does not believe that TVR participation in Rhode Island would be any different.[19] Moreover, the opt-in BCA scenario is cost-effective by a wide margin, limiting the risk that customer migration to third-party suppliers would erode the BCA.

In the case of expanded enrollment in net energy metering (NEM) or remote net metering, customers who have previously sized their systems to offset their annual bill might pay less attention to price signals provided by TVR and energy savings opportunities provided by energy insights and bill alerts. Nonetheless, the BCA analysis in Section 10.4.4 shows that AMF program cost effectiveness requires little to no customer response to these benefits. The customer response-related benefit categories (e.g., TVR and Energy Insights / Bill Alerts) are projected to provide approximately $292 million (opt-out) or $175 million (opt-in) in NPV benefits based on statewide load between 4,800 and 5,800 GWh. With co-deployment of AMF in Rhode Island and upstate New York, such benefits could essentially fall to zero, and the program would be expected to remain cost effective. As such, even a significant rise in NEM-qualified generation from its current total of less than 5% of residential and small commercial load, is not expected to render AMF deployment cost ineffective.

Setting aside the potential impact of NEM enrollment, it is not clear that NEM participation will negatively affect AMF benefit realization. Indeed, customers who enroll in net metering may be responsive to TVR, energy insights and bill alerts, as they are already engaging with their energy usage enough to seek out net metering opportunities. Should these customers accordingly decrease their gross bills, community net metering participants might choose to reduce their share of projects in response. Also, increases in household electrical load due to the proliferation of heat pumps and EVs could result in existing NEM customers requiring additional electricity to cover increases in load. These customers would likely seek ways to save through participation in

[19] *See e.g.*, MA Grid Mod Phase II Investigation, *supra* note 15, Reply Comments of Good Energy, L.P. (Sept. 4, 2019) ("Good Energy's primary concern in any rollout of TVR for utility Basic Service is that the same opportunities to offer TVR are afforded to municipal aggregations.").

TVR and the CEMP to recalibrate usage and therefore bills to their NEM credits. The uncertain variables of customer response and DER adoption make it difficult to confidently assume that net metering participation will affect AMF benefits in one direction or another.

To help further mitigate these concerns, the Company will seek to coordinate with towns that are considering adopting or have already adopted community choice aggregation as part of the CEP. Additional details on the CEP are included in Attachment A.

2.3. Programs in Other Jurisdictions

To ensure this business case incorporated the learnings of other utilities that sought approval for AMF investments and programs, the Company performed a jurisdictional survey of utility filings that requested approval for different types of investments (e.g., AMF only or AMF plus a GMP) across the country. The Company reviewed filings from the following utilities:

- Hawaiian Electric Company (HECO)
- Southern California Edison (SCE)
- Public Service Electric and Gas Company (PSE&G) in New Jersey[20]
- Orange and Rockland (ORU) in New York
- Xcel Power in Minnesota
- Duke Energy in North Carolina
- Dominion Power in Virginia
- Dayton Power & Light (DP&L) in Ohio

The filings for each of the utilities were assessed for the scope of the proceeding, investment/program approval request, and the elements of the request that led to its eventual approval or elements that led to additional review or ultimate denial. While each proceeding had elements of local policies and issues that are not transferrable, there were several overarching learnings the Company drew from the survey to inform this Updated AMF Business Case. The learnings include:

1. Concrete near-term programs and actions that fit into a long-term strategic vision/roadmap are key for regulatory approval. Leveraging information from pilots at affiliate companies or other utilities is also important.

    Close coordination of the AMF and GMP filings ensures the AMF investment is being made as part of the Company's broader longer-term roadmap for both grid modernization and the customer experience. AMF is one of the foundational near-

[20] *See Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future-Energy Cloud (CEF-ED) Program on a Regulated Basis*, New Jersey Board of Public Utilities Docket No. EO18101115, Decision and Order Approving Stipulation (January 7, 2021) [hereinafter PSE&G AMF Order] (approving PSE&G's proposal to install approximately 2.2 million AMI meters).

term programs the Company believes is necessary to enable a host of customer- and grid-facing functionalities in the GMP roadmap.

2. Pilots and phased implementation are an important way for commissions to become comfortable with new technologies and rate designs.

   To ensure that the AMF investment is robust and considers the learnings of similar programs elsewhere, the Company distilled key learnings from its affiliates' Worcester Pilot and Clifton Park, New York Reforming the Energy Vision (REV) Demand Reduction Demonstration (Clifton Park Demonstration), which provided a good foundation for this filing, particularly around customer engagement strategies. Appendices 10.8 and 10.9 provide additional information on the Worcester Pilot and Clifton Park Demonstration, respectively.

3. Stakeholder participation is integral for success.

   All successful AMF filings reviewed had robust stakeholder processes that informed the ultimate AMF investment decisions and program designs. The PST Advisory Committee that was convened to review and guide the Company's approach to this Updated AMF Business Case, as well as the PUC workshops, are reflective of a similar type of effort underway in Rhode Island. Section 2.1 highlights the benefits of the stakeholder process and the ways it shaped the Company's Updated AMF Business Case, including refining the BCA, program implementation, and customer engagement strategies.

4. AMF filings need to address obsolescence issues directly as technologies are rapidly evolving in the marketplace.

   Stakeholders are concerned about the longevity of the AMF solution given long payback periods and evolving customer and grid needs. The Company has evaluated the capabilities and technology roadmaps of the AMF vendors as part of the procurement effort. The solution the Company is proposing represents the latest generation of AMF technology. It includes over-the-air firmware upgrades and grid-edge computing platform capabilities, such as software applications that are deployable to the meters for both grid- and customer-facing use cases. The capabilities of the new generation AMF solutions help to mitigate stakeholder concerns regarding technology obsolescence.

5. Accountability, such as reporting and performance metrics, can facilitate efficient project management and delivering benefits for customers.

   The Company has woven accountability throughout this Updated AMF Business Case to ensure customers realize the benefits of the proposed AMF investments. As discussed in detail in the Metrics and Performance Incentive Measures

Roadmap (Attachment D), the Company has included plans for reporting and measuring program progress and effectiveness through a series of customer engagement and operational metrics. In addition, the Company plans to continue to work with the Division, OER, and interested stakeholders over time to develop performance incentives that would measure the Company's ability to deliver AMF-related benefits. The various accountability elements will help to ensure customers realize the benefits of AMF.

2.3.1. Docket 4600 Alignment

In its Report and Order in Docket No. 4600, the PUC adopted a set of goals, rate design principles, and a new Rhode Island benefit-cost framework for use in future dockets.[21] The Docket 4600 Guidance Document discusses the application of each, and specifies that any proponent of a program proposal with associated cost recovery will need to meet the Docket 4600 goals, principles, and framework.[22] The PUC further stated that "in any case that proposes new programs or capital investment that will affect National Grid's electric distribution rates, the impact of any increased ratepayer recovery should also reference the goals, rate design principles, and Benefit-Cost Framework."[23] To this end, the Company has applied the goals, and Docket 4600 Framework to this Updated AMF Business Case. Section 1.6 of the Company's GMP and Section 4.4 below, discuss how the GMP investments, and specifically AMF, advances, detracts from, or is neutral to the Docket 4600 goals. The application of the Docket 4600 Framework is further discussed below.

In its Report and Order in Docket No. 4600, the PUC held that the Docket 4600 Framework should serve as a starting point in making a business case for a proposal, but also that it should not be the exclusive measure of whether a specific proposal should be approved.[24] The PUC recognized that there may be outside factors that need to be considered regardless of whether a specific proposal is determined to be cost-effective or not, such as statutory mandates or qualitative considerations, and that such application is consistent with the PUC's broad regulatory authority in setting just and reasonable rates.[25] The AMF BCA uses the Docket 4600 Framework to evaluate the cost-effectiveness of the proposed investment.

For purposes of this business case, the Company grouped the benefit categories identified in the Docket 4600 Framework as follows: 1) categories considered in the AMF BCA for the 2017 PST Plan filing in Docket No. 4780; 2) categories that were not formerly included, but that have been

[21] *See* Report and Order No. 22851 at 6, 29.

[22] *See* Docket 4600 Guidance Document at 2.

[23] *Id.* at 6.

[24] Report and Order No. 22851 at 23.

[25] *Id*.

quantified for this BCA; and 3) categories that are discussed qualitatively for the purposes of this Updated AMF Business Case. A diagram of the relationships between Docket 4600 Framework categories and the AMF BCA appears in Figure 2-2.

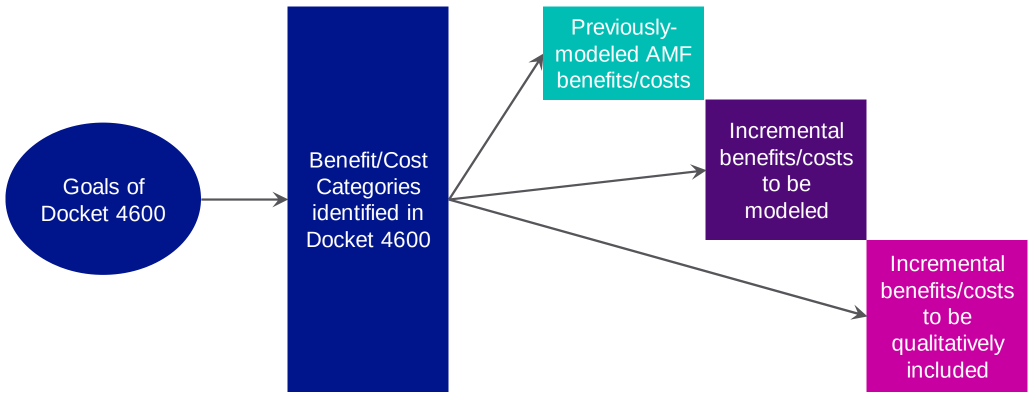

Figure 2-2: Schematic diagram showing the relationship between the Docket 4600 Framework and the costs and benefits included in the AMF BCA. Note that the rightmost three boxes represent all the categories included in the Docket 4600 Framework, though the relative sizes of these boxes are not scaled meaningfully.

Categories that have not been quantified for this business case may have been left to qualitative analysis for three reasons: 1) the category may not apply to AMF; 2) the category may be difficult to accurately quantify; or 3) the category may have a small enough impact that its quantification was deemed negligible. Consistent with the Docket 4600 Guidance Document, the impacts of qualitative categories should be considered in the assessment of the business case. Table 8-1 provides a mapping between quantified Docket 4600 categories and benefit categories of the AMF BCA, along with values of each Docket 4600 category within the context of the AMF proposal. Appendix 10.5 provides a full list of Docket 4600 Framework categories, including explanations of why the Company identified some categories as qualitative.

To ensure the BCA covered all the potential benefits and costs introduced by an AMF investment, the Company surveyed several other utility filings for AMF and grid modernization plans to understand the scope of the BCA (e.g., AMF only, AMF and GMP) as well as the type of cost-effectiveness test that was being applied (e.g., least-cost best fit, societal cost test). This survey also provided a benchmark for benefit and cost categories to be included in the Company's AMF BCA. The results of the survey included in Table 2-4 show that the scope and breadth of the Company's BCA for both AMF and the GMP are more thorough than most other recent filings in the country because the Company applied the Docket 4600 Framework.

Table 2-4: Comparison of Utility BCAs for AMF and GMP

Utility – State	AMF Least Cost Best Fit	GMP Least Cost Best Fit	AMF Full BCA	GMP Full BCA
Hawaiian Electric (HECO) – HI	X	X		
Southern California Edison (SCE) – CA		X		
Public Service Electric and Gas Company (PSE&G) – NJ			X	
Orange and Rockland (ORU) – NY			X	
Xcel Energy – MN			X	X
Duke Energy (DEC) – NC			X	
Dominion Power – VA	X	X		
Dayton Power & Light (DP&L) – OH			X	X
Illinois Utility of the Future stakeholder process – IL				
National Grid – MA			X (combined AMF and GMP)	
National Grid – NY			X	X
National Grid – RI			X	X

3. Background: The Current State of Metering

The Company began the process of evaluating metering solutions with a survey of technology in place throughout the United States. It continued that effort by analyzing the metering proposals across the jurisdictions covered by its affiliates, and then applied that information to the specific state of metering in Rhode Island. With AMF either approved or installed for more than 70% of residential customers in the United States, including the Company's New York affiliate, this section focuses on the current state of AMF technology. Sections 4 and 5, on the other hand, consider grid modernization objectives and solutions from a technology-neutral perspective.

3.1. AMF in the United States

According to the Federal Energy Regulatory Commission (FERC), "[a]dvanced meters are the most prevalent type of metering deployed throughout the country, accounting for more than half of all meters installed and operational in the United States."[26] That number is expected to

[26] Federal Energy Regulatory Commission, *2019 Assessment of Demand Response and Advanced Metering*, Staff Report 1 (December 2019).

increase in the coming years as approved implementation programs continue and proposals for approval are advanced in numerous states. The Edison Foundation's Institute for Electric Innovation (IEI), for example, has identified that over fifty electric utilities across the United States have fully deployed smart meters as of the end of 2018.[27] Figure 3-1, from IEI, shows the deployment of residential smart meters by state in 2018.[28] IEI further reports that as of 2018 a total of 88 million smart meters have been deployed across the country, and that number is expected to climb to 98 million in 2019, and 107 million by the end of 2020 (*see* Figure 3-2).[29] This would represent approximately 85% of all households in the United States.

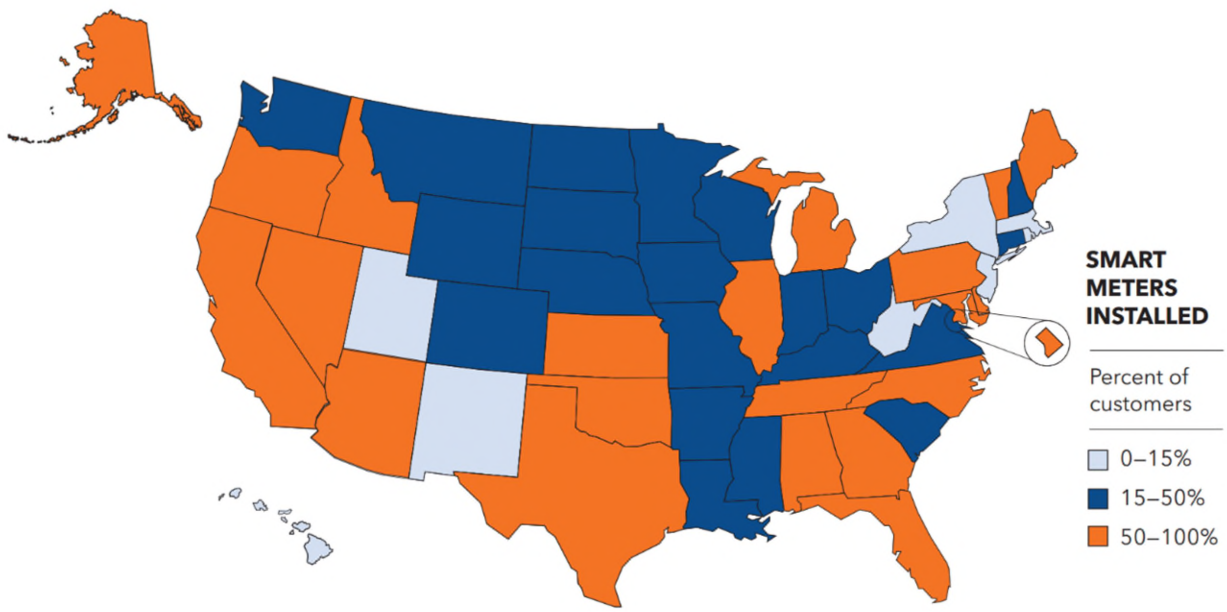

Figure 3-1: Residential smart meter deployment by state, 2018.

[27] *See* Adam Cooper & Mike Shuster, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid (2019 Update)*, Institute for Electric Innovation (December 2019).

[28] *Id.* at 2.

[29] *Id.* at 1; *see also* U.S. Energy Information Administration, *Electric Power Sales, Revenue, and Energy Efficiency Form EIA-861 Detailed Data Files for 2019*, https://www.eia.gov/electricity/data/eia861/ (October 6, 2020).

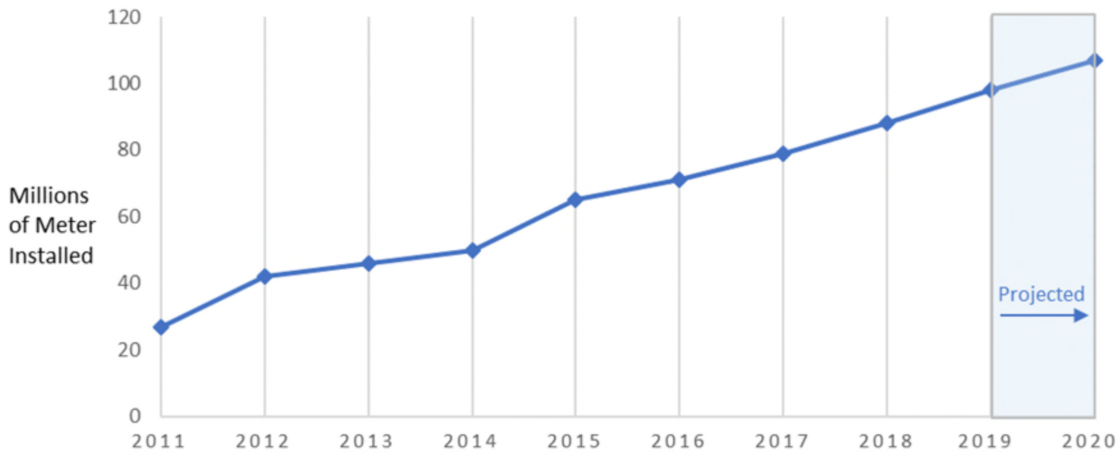

Figure 3-2: Yearly Historical and projected US AMF deployment[30]

Utility proposals for AMF implementation experienced mixed results in 2018 and 2019. Regulators approved plans in Florida (Duke Energy Florida), Mississippi (Mississippi Power Company), North Carolina (Duke Energy Carolinas, Duke Energy Progress), Hawaii (Hawaii Electric), and South Carolina (Dominion Energy), while denying proposals in New Mexico (Public Service New Mexico), Massachusetts (National Grid and Unitil), Kentucky (Louisville Gas & Electric Company and Kentucky Utilities), and Virginia (Dominion Energy). In the states where utility AMF proposals were denied, the regulators did not rule out future approval but identified areas of concern (such as those listed in Section 2.2.1) to address before moving forward. As depicted in Figure 3-3, at the end of 2019, dockets considering AMF deployment requests were open in Hawaii, Indiana, Michigan, Minnesota, Missouri, New Jersey, New York, Ohio, South Carolina, Virginia, and Washington.

In 2020, regulators in Massachusetts and New York have shown renewed interest in AMF proposals as a key component of delivering clean energy benefits in line with statewide policy goals, evolving customer expectations, and the operational needs of utilities. For example, in July, the Massachusetts Department of Public Utilities (DPU) initiated an investigation into customer-facing grid modernization technologies, including AMI.[31] Then, in November 2020, the New York Public Service Commission (NYPSC) issued two orders, including an order for the Company's upstate New York affiliate, approving plans to deploy approximately 3 million

[30] Adapted from: *Electric Company Smart Meter Deployments: Foundation for a Smart Grid*.

[31] MA Grid Mod Phase II Investigation, *supra* note 15, Vote and Order Opening Investigation (July 2, 2020).

electric AMI meters and 1.24 million AMI-enabled gas modules across Upstate New York.[32] Early in 2021, there has been further action with regard to AMF, with the New Jersey Board of Public Utilities approving PSE&G's proposal to deploy approximately 2.2 million AMF meters across its service territory.[33]

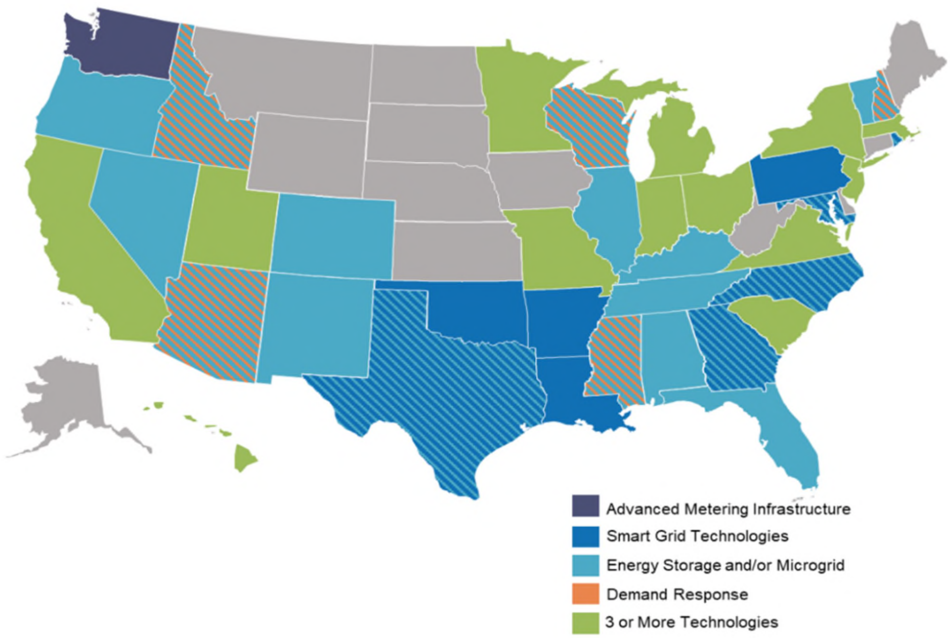

Figure 3-3: Proposed Grid Modernization Deployments by Technology Type[34] (Q4 2019)

[32] *See* NY AMI Order, *supra* note 4 (approving the deployment of approximately 1.7 million electric AMI meters and 640,000 AMI-enabled gas modules for the Company's New York affiliate); *see also* NYPSC Case Nos. 19-E-0378, et al., Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal with Modifications (November 19, 2020) [hereinafter Avangrid NY Rate Case Order] (approving the deployment of approximately 1.3 million electric AMI meters and 600,000 AMI-enabled gas modules for Avangrid's two New York utilities).

[33] *See* PSE&G AMF Order, *supra* note 20, at 13.

[34] NC Clean Energy Technology Center, *The 50 States of Grid Modernization*, Q4 2019 Quarterly Report & Annual Review 15 (February 2020), https://nccleantech.ncsu.edu/wp-content/uploads/2020/02/Q42019-GridMod-Exec-Final2.pdf.

3.2. National Grid Proposals in Other States

The Company's upstate New York affiliate (Niagara Mohawk Power Corporation or NMPC) serves approximately 1.6 million electric customers and 600,000 gas customers. In 2016, NMPC filed a Distributed System Implementation Plan (DSIP), which set forth a plan for investments needed to modernize its system and enhance its Distributed System Platform (DSP) capabilities.[35] In the DSIP, NMPC identified AMI as a foundational component of its grid modernization effort. The DSIP included an AMI business case that described and compared alternative AMI deployment options and, based on the results of the BCA, proposed territory-wide implementation as the cost-effective fit-for-purpose solution.

In April 2017, NMPC filed a more detailed and updated AMI business case supporting full deployment as part of its general rate case.[36] A settlement agreement in the rate case was reached that required NMPC to refine and enhance its AMI business case through a collaborative process – it initiated the collaborative in April 2018. The collaborative process culminated in the filing of NMPC's refined and updated AMI business case and petition on November 15, 2018, requesting approval to deploy AMI to its electric and gas customers. Following the filing, Niagara Mohawk Power Corporation continued to collaborate with New York Department of Public (DPS) staff. The ongoing efforts led to the identification of additional benefit opportunities in line with peer utility filings, as well as reduced costs, which enhanced the case for AMI in New York. The enhancements were outlined in five supplemental filings.[37] On November 20, 2020, the NYPSC approved NMPC's AMI proposal.

With the New York AMI Order, the NYPSC authorized NMPC to proceed with deploying approximately 1.7 million electric AMI meters and 640,000 AMI-enabled gas modules, and the associated communications network, across its service territory. As part of its findings, the NYPSC addressed the three unmet need categories discussed above (i.e., customer expectations, operational/system, and clean energy):

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[35] *Proceeding on Motion of the Comm'n. in Regard to Reforming the Energy Vision*, NYPSC Case No. 14-M-0101 (A subsequent corrected DSIP was filed on July 1, 2016 to fix a formatting issue).

[36] *See Proceeding on Motion of the Comm'n. as to the Rates, Charges, Rules and Regul. of Niagara Mohawk Power Corp.d/b/a National Grid for Elec. and Gas Serv.,* NYPSC Case Nos. 17-E-0238 and 17-G-0239 [hereinafter 2017 NY Rate Case], Direct Testimony of the AMI Panel (April 28, 2017).

[37] *See* 2017 NY Rate Case, *supra* note 36 (Supplemental filings dated February 22, 2019; September 4, 2019; January 22, 2020; September 18, 2020; and October 28, 2020); *see also Proceeding on Motion of the Comm'n. as to the Rates, Charges, Rules and Regul. of Niagara Mohawk Power Corp. d/b/a National Grid for Elec. and Gas Serv.*, NYPSC Case Nos. 20-E-0380 and 20-G-0381 (2020 NY Rate Case), Direct Testimony of the AMI Panel (July 31, 2020).

- **Customer Expectations:** "[T]he deployment and use of AMI can be harnessed to transform the relationship between National Grid and its electric and gas customers. With AMI, National Grid can improve its response to power outages, as the Company will have more accurate and granular information regarding the voltage and current status of customers' services. AMI can empower customers by providing them with information about their energy usage and allowing them to take action to manage their electric and gas costs."[38]

- **Operational/System:** "National Grid will likely need to invest funds in its metering infrastructure in the near future, whether to replace AMR meters and gas modules in kind, or to upgrade to AMI. This presents an opportune time to upgrade to AMI while avoiding the costs of replacing the existing AMR meters in kind."[39]

- **Clean Energy:** "AMI is an important and valuable contribution to enabling the Company to assume the role of the DSP, to increasing use of DERs to support system operation, to increasing the use of measures such as VVO to reduce energy use and emissions, and to facilitating customer access to products and services provided by third-parties."[40]

The NYPSC evaluated the proposal using the AMI BCA model developed as part of NMPC's AMI business case.[41] Similar to the BCA model accompanying this Updated AMF Business Case, NMPC provided assumptions based on both an opt-out TVR scenario (NMPC's recommended approach) and an opt-in TVR scenario.

The NYPSC based its decision on the information in NMPC's opt-in scenario with three modifications. First, the NYPSC approved approximately $9.07 million in incremental costs to reduce data latency from 15-minute intervals available to customers every four hours, to 15-minute intervals available every 30-45 minutes.[42] Second, the NYPSC used an opt-in TVR participation assumption of 15%.[43] Third, the NYPSC incorporated an energy usage reduction of 1.5% from customer behavior.[44] With these adjustments, the NYPSC approved NMPC's AMI proposal, finding that using the more conservative assumptions "suggests that the benefit-cost

[38] NY AMI Order, *supra note 4,* at 26-27.

[39] *Id.* at 36.

[40] *Id.* at 27.

[41] *See id.* at 35 (noting that the NYPSC compared NMPC's BCA assumptions, costs, and benefits with those used by other utilities, and found the model to be reasonable).

[42] *Id.* at 31.

[43] *Id.* at 35-36.

[44] *Id.* at 36

ratio [of 1.10] is durably above one."[45] By comparison, incorporating the same changes in the Base Case scenario supporting this Updated AMF Business Case results in an opt-out BCA of 2.18 and an opt-in BCA of 1.64.[46]

The Company's Massachusetts affiliates (Massachusetts Electric Company and Nantucket Electric Company) serve approximately 1.3 million electric customers. They filed a grid modernization plan in the Grid Modernization proceeding before the DPU on August 19, 2015 and an updated plan on June 16, 2016. The grid modernization plan included options for territory-wide, targeted, and opt-in AMF deployment. On May 10, 2018, the DPU issued an order affirming its commitment to grid-facing technologies, such as VVO, while stating its intent to launch an AMF stakeholder process.[47] Although the DPU did not approve AMF deployment at the time, it acknowledged that AMF is "an important tool in meeting … grid modernization objectives."[48] It also "found that the primary benefits of advanced metering functionality are derived from reduced peak usage as customers respond to pricing signals."[49]

On July 2, 2020, the DPU initiated an investigation into the targeted deployment of AMI meters and TVR for EV customers.[50] The Company's affiliates filed initial comments on August 13 and reply comments on September 4, affirming their interest in working with the DPU to facilitate EV adoption in Massachusetts, while also noting that the electromechanical AMR metering assets currently deployed in the Commonwealth are reaching the end of their useful life. Similar to the process used in Rhode Island, the Company's Massachusetts affiliates advocated for a regulatory mechanism to consider meter replacement options, including the filing of an AMI business case. As part of the investigation, the DPU hosted four technical conferences, addressing issues related to the status of existing meters, trends in meter deployment, AMI meter functionality, back-office systems, TVR, municipal aggregation, and AMI opt-out provisions.[51] The Massachusetts docket is open, and the Company's Massachusetts affiliates remain

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[45] *Id*.

[46] The incremental cost of $1.74 million (20-year NPV) to make data available to Rhode Island customers every 30 to 45 minutes is already incorporated in the Base Case scenario.

[47] *See Petition of Massachusetts Elec. Co. and Nantucket Elec. Co. d/b/a National Grid for Approval by the Dep't of Pub. Util. of its Grid Modernization Plan*, D.P.U. 15-120, Order at 2, 3, 236 (May 10, 2018).

[48] *Id*. at 2.

[49] *Id*.

[50] *See* Vote and Order Opening Investigation.

[51] *See* MA Grid Mod Phase II Investigation, *supra* note 15, Memorandum Regarding Agenda for November 17, 2020 and November 20, 2020 Technical Conferences (November 4, 2020); *see also* MA Grid Mod Phase II Investigation, Memorandum Regarding Agenda and Registration Links for December 3, 2020, and December 4, 2020 Technical Conferences (November 25, 2020).

committed to working with the DPU as part of the process to further refine and advance their AMF/AMI proposals.

3.3. Metering in Rhode

The Company provides energy delivery services to approximately 496,000 electric customers across 38 cities and towns and 272,000 natural gas customers in 33 cities and towns in Rhode Island. The Company currently uses AMR technology throughout its service territory to read the majority of electric and gas meters.[52] Deployed in the early 2000s, the electric and gas meters are equipped with a communication module that sends a radio signal to a fleet of service vehicles as they drive by to collect monthly reads. There are two kinds of electric meters in the field today:

1) Electromechanical meters that were retrofitted with AMR communication modules during the initial deployment of AMR; and

2) Solid-state AMR meters with the communication module built-in, which were deployed following initial AMR roll-out. The Company's gas meters are equipped with an external communication module that records and transmits gas consumption data measured by the gas meter. Each of the AMR technologies currently deployed is depicted in Figure 3-4.

Solid State AMR Meter | Electro-mechanical Meter | Gas Meter with AMR Module

Figure 3-4: Currently deployed AMR meter types

[52] A small number of G32 large retail customers, approximately 100, have interval meters read by the MV90 system daily. These meters are to be replaced as part of the Company's 2G to 4G/IEE conversion project, which is replacing existing interval metering read via MV-90 with a cellular-based interval metering solution that is in place as part of the New York Clifton Park solution and integrated via the pilot's vendor partner Itron and their IEE meter reading software.

A majority of the current electric AMR electric meters and gas modules will reach the end of their estimated 20-year life by calendar years 2023 and 2024. The age of the gas AMR communication modules is more evenly distributed as the gas modules are routinely replaced as part of the existing 10- to 15-year gas meter replacement program. Figure 3-5 provides the age distribution of the electric AMR meters and gas modules.

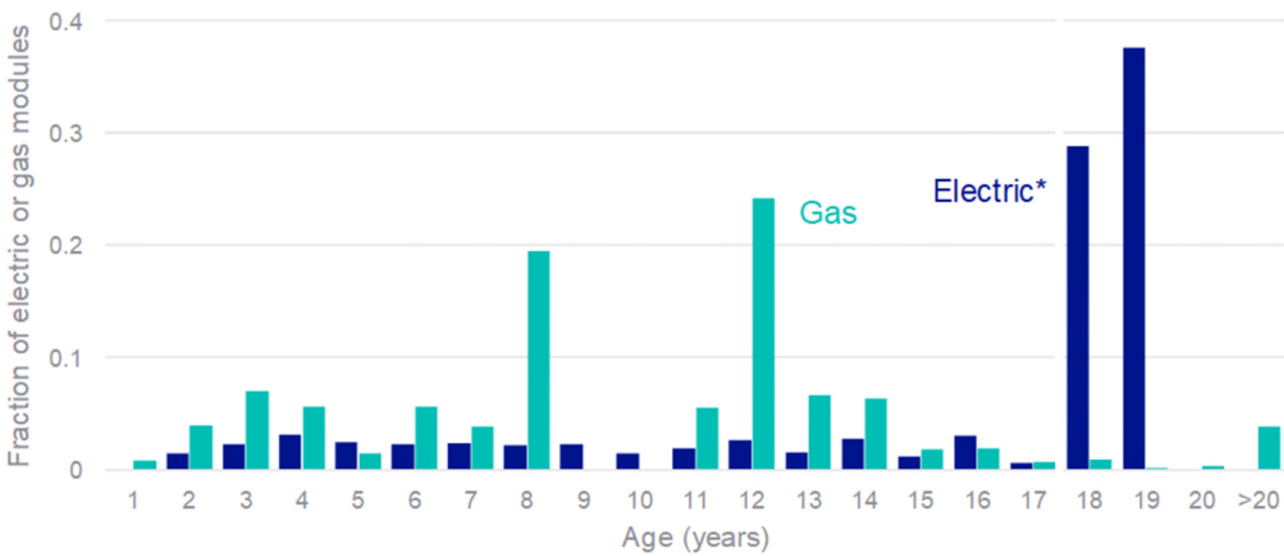

Figure 3-5: Current equipment age of electric and gas modules

*Electric modules data updated in 2017. Gas module data updated as of December 31, 2018

3.3.1. Counterfactual AMR Investment

Given that current AMR meters are at the end of their expected useful lives, noninvestment in AMF would require reinvestment in AMR (i.e., there is not a "do nothing" option). The Company has not completed an extensive revenue requirement and bill impacts analysis for reinvesting in AMR. However, the counterfactual impacts from an AMR investment can be estimated using the avoided AMR costs and avoided feeder monitoring sensors costs in the BCA model.

Table 3-1: AMF investment costs compared to counterfactual AMR reinvestment costs

	AMF Year 1	AMF Year 2	AMF Year 3	AMF Year 4	AMF Year 5	20-year NPV	20-year Nominal
AMF cost less Non-OMS benefits ($M)	21	25	88	47	4	188	263
Counterfactual AMR cost (M$)	3	6	38	30	4	100	161
AMR percent of AMF cost	16%	25%	43%	64%	119%	53%	61%

Table 3-1 shows a comparison between the costs included in the AMF revenue requirement and the costs that would be included in a counterfactual AMR revenue requirement. The "AMR percent of AMF cost" row can be read as the fraction of AMF costs that are unavoidable, given the counterfactual AMR investment that would be required in the absence of AMF. Though costs continue throughout the 20 years of the analysis, the table highlights only the first 5 years to show the AMF and AMR deployment costs in years 3 and 4.

The counterfactual AMR investment includes AMR meters, AMR installation labor, AMR-related Customer Meter Services, and feeder monitoring sensors that would not be required in a full-scale AMF deployment scenario. This estimation only considers the most direct counterfactual costs. It does not capture secondary costs such as the costs to program and operate limited TVR using AMR technology (i.e., triple ERT AMR meters), or the equipment costs associated with loads that are higher and peakier due to lack of benefits from enhanced functionalities such as energy insights and bill alerts. In short, the Company would expect a more rigorous BCA to show higher percentages of unavoidable costs based on the inclusion of these other items. The high-level estimate suggests that, on an NPV basis, over half of the AMF costs cannot be avoided, because of the need to replace the AMR meters.

3.3.2. Net Metering Requirements in Rhode Island

In Rhode Island, net metering is administered under the Company's electric tariff. The Company believes an AMF meter will be well-suited to serve net metered customers. In implementing this approach using AMF, the Company can draw from the experience of its affiliates in New York (Clifton Park Demonstration) and Massachusetts (Worcester Pilot), which included elements of net metering with AMF meters.

Net metering customers and community (or remote) net metering customers in Rhode Island receive dollar credits based on the energy generated by their associated distributed generation systems. The credits are determined by default service, transmission, distribution, and transition charges for the rate used by a behind-the-meter (BTM) customer, or the C-06 rate for community net metered projects. The credits are applied monthly to the total customer bill, and credit up to

25% of the annual total bill may be carried over at the end of the year. The use of AMF would not affect the methodology for calculating and applying net metering credits.

The use of an AMF meter for net metering or Renewable Energy Growth (REG) programs will allow for accurate reporting of either net generation (under net-metering) or total generation (under REG) to the ISO-NE so that wholesale revenues can accrue to the Company and would be used to offset the costs of either program.

As the AMF meters proposed in this Update AMF Business Case have interval metering, any expansion or changes to the net metering or REG programs could occur without requiring the meter to be replaced. Over-the-air software and firmware updates will allow for remote re-programming if needed. In addition, the use of raw interval data can be manipulated by the MDMS proposed to allow for numerous billing scenarios, including time-varying credit payments, which would better reflect the value of DG to the system and would mimic the TVR pricing expected for consumption. In addition, virtual bills for multiple off-takers from a solar or wind farm (community renewable energy applications) can be constructed if the need arises with the use of the raw data from an AMF meter. Finally, as explained in Section 2.2.1, possible expansion of virtual net metering programs in Rhode Island is not expected to materially affect the AMF benefit-cost ratio.

4. Grid Modernization Roadmap and AMF Integration

This Updated AMF Business Case is an integral part of the Company's overarching GMP. The GMP consists of both a five-year implementation plan and a ten-year roadmap. The GMP expands on the grid modernization plans provided in Docket No. 4780, and similar to this Updated AMF Business Case, addresses input received from the Subcommittee.

National Grid, like other utilities around the country, recognizes that major changes across the energy industry, including changes in customer preferences for energy management and a shift toward renewables and electric transportation, are shaping the ways in which the distribution system needs to function. The Company must be prepared for these evolving impacts and continue to manage the electric distribution system in a safe and affordable manner that maintains top-tier service reliability. Many GMP investments, including AMF, enable the Company to provide both customer- and grid-facing benefits in this evolving landscape. This section provides a summary of the GMP roadmap and describes how AMF enables several grid modernization functionalities and integrates with other grid modernization efforts to advance each of the goals for the "new" electric system, as outlined in Docket 4600. Additional detail is set forth in the GMP.

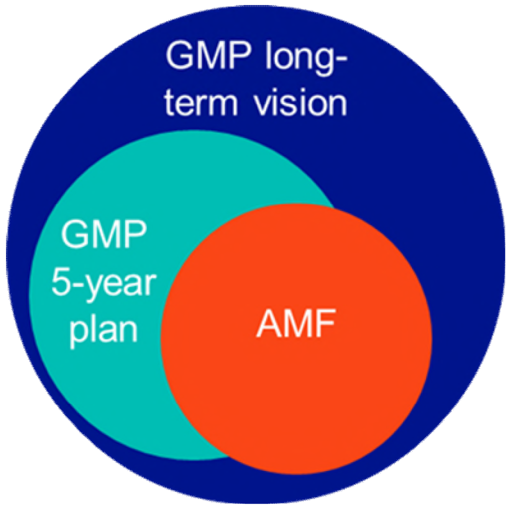

Figure 4-1: Visual representation of AMF investment in GMP 5-year Implementation Plan and 10-year Roadmap

4.1. GMP Development Approach and Objectives

As illustrated in Figure 4-2, to develop a set of grid modernization solutions to meet Rhode Island's needs through 2030, the Company followed a stepwise and iterative approach. The Company began by identifying GMP objectives based on customers' needs and state goals, particularly Docket 4600 "goals of the new electric system," as outlined in Table 4-1. Next, the Company completed a Future State Assessment to develop and study reasonable future state scenarios. By studying the scenarios, with consideration of the GMP objectives, the Company developed a set of required functionalities. Then, the Company identified a proposed solution and ten-year roadmap necessary to realize the capabilities and functionalities based on an analysis of traditional solutions using standard equipment compared to grid modernization alternatives with input from subject matter experts across the Company. Finally, the Company developed a BCA based on results of the Future State Assessment of the distribution system. The following subsections highlight customer needs and state goals, GMP objectives, AMF impacts on GMP functionalities, the proposed GMP solution, and a roadmap of GMP investments. More detail, including descriptions of the Future State Assessment and BCA, is included in the GMP filing.

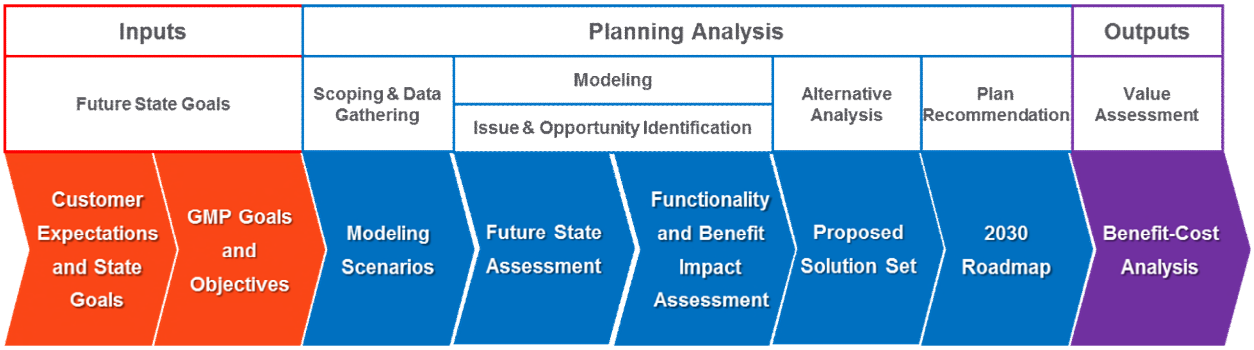

Figure 4-2: Illustration of GMP Solution Assessment Approach

The Docket 4600 goals center on the critical question: what can and should the new electric system be able to accomplish? Table 4-1 shows the alignment between the Docket 4600 goals and the GMP objectives. Section 4.4 provides additional detail on how GMP investments, including AMF, align with Docket 4600 goals.

Table 4-1: GMP Objectives Alignment with Docket 4600 Goals

Goals For "New" Electric System	GMP Objectives
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	1) Give customers more energy choices and information
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)	2) Maintain and enhance reliable, safe, clean, and affordable energy to Rhode Island customers over the long term
Strengthen the Rhode Island economy, support economic competitiveness, and retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	
Appropriately charge customers for the cost they impose on the grid	
Address the challenge of climate change and other forms of pollution	3) Build a flexible grid to integrate more clean energy generation
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	
Appropriately compensate the distribution utility for the services it provides	
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives	

4.2. GMP Functionalities

In assessing the key functionalities necessary to achieve GMP objectives, the Company reviewed and considered the full set of functionalities identified by the DOE Modern Grid Initiative (DSPx) guidance for applicability in Rhode Island during the GMP time horizon.[53] This multi-volume guide discusses the expected functionalities of a modern distribution grid and offers a comprehensive view of the potential technology stack needed to effectively manage the evolving distribution system. The Company has actively participated in workshops and provided

[53] DOE's Modern Grid Initiative works with public and private partners to develop the concepts, tools, and technologies needed to measure, analyze, predict, protect, and control the grid of the future. Multi-volume guidance documents are available on the Pacific Northwest National Laboratory's website: https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx;

feedback in support of the DOE's development of the guide. Using the DSPx guidance, the Company developed a full list of GMP functionalities, which is described in detail in the GMP filing.

Table 4-2: AMF Functionalities & Impact on GMP Functionalities[54]

GMP Key Functionality	AMF Enabling Functionality	AMF Impact on GMP Functionality
Customer Information	CEMP, GBC, Integration w/ In-Home Technologies	Foundational
Advanced Pricing	Interval Energy Usage Data	Foundational
Remote Metering	Remote Interval Meter Reading, Remote Connect & Disconnect	Foundational
Observability (Monitoring & Sensing)	Load & Voltage Data	Enhancement
Power Quality Management	Load & Voltage Data	Enhancement
Distribution Grid Control	Load & Voltage Data	Enhancement
Grid Optimization	Load & Voltage Data	Enhancement
Reliability Management	Automated Outage & Restoration Notification, Granular Fault Location	Enhancement
DER Operational Control	Remote Interval Meter Reading, Load & Voltage Data, Operational Telecommunications (Tier 3)	Enhancement

As shown in Table 4-2, AMF is foundational[55] to many of the GMP functionalities and provides significant enhancements to several others, allowing for better observability, planning, and control of the distribution system and DERs. The following is a brief description of how AMF enables these GMP functionalities.[56]

[54] The table does not include all key GMP functionalities.

[55] Foundational means the GMP functionality would not be possible without AMF.

[56] *See also* Section 7.1 of the GMP.

- **Customer Information (Foundational):** The Company's AMF solution proposal would provide access to timely, granular energy usage information for all customer classes through three primary channels: 1) web and mobile devices via the CEMP; 2) data sharing using GBC that will be available on the CEMP; and 3) directly from the meter in real-time through a home-area-network (HAN). AMF also empowers customers to reduce their energy costs using enhanced insights (such as high-bill alerts) based on more granular, timely energy usage data available through the CEMP or through integration with the HAN.

- **Advanced Pricing (Foundational):** AMF provides interval energy usage information required to support TVR and customer load management programs that can be used to shift energy consumption between time periods to reduce energy costs and/or alleviate location-specific constraints on the delivery system.

- **Remote Metering (Foundational):** AMF improves operational efficiency by enabling the Company to reduce O&M costs associated with AMR meter reading, meter investigations, and visits to connect and disconnect service.[57]

- **Observability (Monitoring & Sensing):** AMF provides granular and timely customer load data to support actionable information on the operating state and condition of the distribution grid and DER assets necessary for safe, secure, and reliable operation.

- **Power Quality Management:** The Company expects to achieve an incremental 1% VVO/CVR-based reduction in energy and peak demand by integrating granular AMF voltage data into the VVO control schemes. This data will provide better awareness of feeder voltages compared to only using voltage data from advanced field devices.

- **Distribution Grid Control:** Granular and timely customer load data from AMF supports more accurate load-flow calculations, enabling the system operator to better control power flows on the distribution system and optimize power output from renewable DERs (through an Advanced Data Management System (ADMS) and/or Distributed Energy Resource Management System (DERMS)) to avoided thermal or voltage constraints rather than investing in traditional solutions (e.g., reconductoring, substation upgrades) to relieve the constraints.

- **Grid Optimization:** AMF provides granular customer load data from interval power monitoring at the customer level, which provides a step change in available data for grid planning and operations. While the latency of AMF data is not the same as operational

[57] Any disconnections will be done in compliance with applicable rules and regulations governing terminations of residential electric and gas utility services, including PUC orders and requirements, the Low-Income Home Energy Assistance Program (LIHEAP), and the Arrears Management Plan (AMP) program.

Supervisory Control and Data Acquisition (SCADA) data from advanced field devices, appropriate analytics of the AMF data will significantly improve the load-flow models used by distribution planners and within the proposed ADMS for distribution system operators. Today, feeder-level data combined with generic load shape analysis is used to model remote end-feeder performance. AMF provides more granular, timely values that can be aligned with other system data to create actual loading and voltage profiles at all points along a feeder. This complete data set can be modeled directly and more detailed load and DER forecasts can be developed for planning and operational needs.

- **Reliability Management:** AMF provides autonomous outage notifications, alerting the Company to trouble before receiving customer outage calls. Integrating this functionality with the Company's OMS (via an ADMS) will reduce time from initial outage to Company notification, which is expected to improve the overall outage response. AMF also provides restoration notifications enabling the Company to verify whether power has been restored to all meters, reducing the need for crews to verify restoration (i.e., lights-on truck rolls) and alerting the Company if some meters are still out of power. In addition, AMF provides granular outage data at the customer level, increasing the accuracy of fault location capabilities of an ADMS. More accurate fault location improves operational efficiency through a reduction in field crew hours and vehicle miles traveled, and it improves the isolation and restoration capabilities of Fault Location Isolation and Service Restoration (FLISR).

- **DER Operational Control:** AMF supports DER optimization by providing the interval energy and voltage data at the customer level required for verification and settlement of DER services provided to or received from the grid. AMF also enables the exchange of information[58] and/or control with all residential and small commercial (<25 kW) DER technologies through AMF's investment in a Tier 3 FAN operational telecommunications, which would not be possible without AMF investment.[59]

4.3. <u>GMP Solutions and Roadmap Overview</u>

The last step of the GMP development process is the selection of the technical solutions necessary to achieve the required functionalities. This step is described in detail in the GMP filing for all functionalities except for AMF, which is described in detail in this Updated AMF Business Case (Section 5). Figure 4-3 summarizes the GMP solutions, expected timing, and anticipated filing for cost recovery of the GMP investments. Solutions highlighted in yellow are investments that align with the current rate case and Infrastructure, Safety, and Reliability (ISR) dockets; solutions highlighted in blue are future GMP investments.

[58] The use of this data will be subject to the Data Governance and Management Plan (Attachment B).

[59] Currently, the Company requires a dedicated phone line, remote-terminal unit (RTU), and interval meter for all distributed generation greater than 25 kW, but there are no meter requirements for systems smaller than 25 kW.

The GMP's initial investments are focused on the foundational elements of a modern grid, including Customer Enablement, Control Center & Back Office, and Telecommunications investments, as well as a targeted deployment of Advanced ("Smart") Field Devices driven by planning study reviews to ensure the grid can be operated in compliance with existing standards and targets. Opportunities to optimize performance for the benefit of customers will be targeted to the areas of greatest value by leveraging investments in modular optimizing applications. This approach will allow the Company to efficiently leverage the functionalities of ever-evolving customer expectations, technologies, new programs, and services to meet customer and grid needs. Future investments would be presented for cost recovery in rate cases or ISRs as needed.

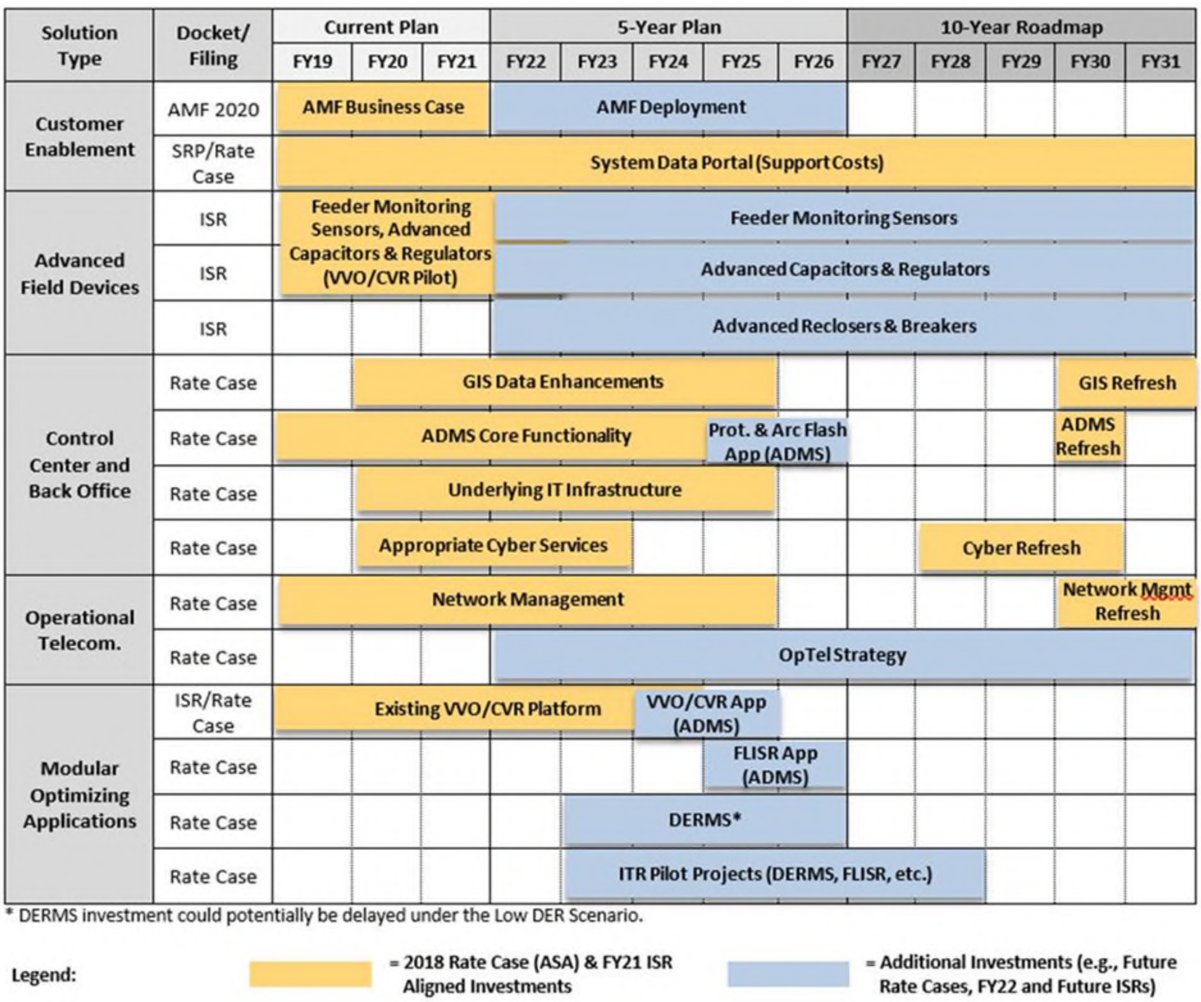

Figure 4-3: Rhode Island Grid Modernization Solutions Roadmap

In addition to playing an integral role in enabling key GMP functionalities and achieving GMP objectives, AMF implementation provides considerable cost synergies with the overall GMP roadmap. First, the ability of AMF to provide more granular, timely voltage and energy data supports GMP planning and operations efforts that would otherwise require more feeder monitoring sensors at significant cost. Second, AMF implementation requires some of the same operational information management, cybersecurity, and operational telecommunications functionalities that are also critical to support other GMP objectives. Thus, AMF implementation creates the opportunity for additional benefits that can build off the GMP investments in underlying IT infrastructure, telecommunications, cybersecurity services, and other costs. The synergies improve the overall BCA for grid modernization.[60]

4.4. GMP & AMF Alignment with Docket 4600 Goals

The Docket 4600 Guidance Document requires that any proponent of a program proposal with associated cost recovery will need to meet the Docket 4600 goals, principles, and framework.[61] Table 4-3, which is included in the GMP, explains how the GMP, including AMF, advances, detracts from, or is neutral to each of the goals for the "new" electric system outlined in Docket 4600. The specific AMF contributions are highlighted in the table for emphasis.

[60] Additional details regarding quantified costs and benefits of the Grid Mod-Only case compared to the Full Grid Mod case (with AMF) are provided in the GMP.

[61] Docket 4600 Guidance Document at 2.

<table>
<tr><th colspan="2">Table 4-3: Alignment of GMP Investments with Docket 4600 Goals</th></tr>
<tr><th>Goals For “New” Electric System</th><th>Advances? /Detracts From? /Is Neutral To?</th></tr>
<tr><td>Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)</td><td><u>Advances</u>: The GMP investments are foundational enablers necessary to effectively manage emerging two-way power flows in a reliable, safe, clean, and affordable manner. The Company’s top priority is to ensure the electric distribution grid continues to operate within compliance of planning criteria and service quality standards. The GMP recognizes that there are opportunities to optimize performance to enhance customer benefits where they are cost effective.

Specifically, GMP investments can reduce customer energy use and distribution system capacity directly through though voltage optimization and conservation control schemes (i.e., VVO/CVR), which enables the operation of distribution feeders at lower overall voltages to reduce electricity consumption from customer appliances. AMF can contribute to incremental benefits in this area by integrating granular AMF voltage data into voltage optimization and conservation control schemes. In addition, AMF will enable customers to become more active in managing and reducing their energy usage through enhanced energy insights (i.e. High Bill Alerts) or integrating AMF with in home technologies.

GMP investments will also avoid multiple utility costs, thereby creating the possibility of improved affordability for Rhode Island customers, including better management of:
Distribution system O&M costs;
Distribution system infrastructure capital costs;
Transmission system infrastructure capital costs; and
Bulk energy purchases.
In addition, GMP investments can reduce customer outage durations through the addition of advanced reclosers, breakers, and fault location, interruption, and service restoration (FLISR) control schemes. AMF has the potential to increase reliability further by enabling better outage management and reduced outage notification time due to autonomous meter outage notifications, which allow field personnel to restore power more quickly without relying on customer calls and substation monitoring.</td></tr>
</table>

Table 4-3: Alignment of GMP Investments with Docket 4600 Goals	
Goals For "New" Electric System	**Advances? /Detracts From? /Is Neutral To?**
Strengthen the Rhode Island economy, support economic competitiveness, and retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	Advances: The GMP investments will help more Rhode Island customers reduce their energy costs and earn additional revenue by enabling them to invest in their own DER technologies in areas that are most cost-effective for these resources. In addition, **GMP construction spending, including AMF, will create additional jobs in Rhode Island**. Indirectly, GMP impacts are felt in the local supply chain, since industries are providing goods and services for the GMP implementation. Induced impacts are felt mainly in the local service sector, such as increased retail activity and hiring as the direct and indirect workers spend a portion of their incomes locally.[62]
Address the challenge of climate change and other forms of pollution	Advances: **GMP investments, including AMF, will reduce greenhouse gases (GHGs) and other harmful emissions by enabling reduced energy use (e.g., VVO/CVR, High Bill Alerts) and renewable DG curtailment.** The investments will also enable more cost-effective interconnection and better utilization of clean DERs (e.g., solar DG, EVs, EHPs) into the electric distribution grid, which will reduce Rhode Island's reliance on more carbon-intensive bulk generation technologies. **In addition, AMF will enable customers to become more active in managing and reducing their energy usage. Finally, additional emissions reductions will be realized due to a reduction in truck rolls due to improvements in operational efficiency.**

[62] *See* Section 7.5.6 for the full economic development impacts assessment.

Table 4-3: Alignment of GMP Investments with Docket 4600 Goals	
Goals For "New" Electric System	**Advances? /Detracts From? /Is Neutral To?**
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	Advances**:** GMP investments can reduce DER interconnection costs and enable improved customer DER experience, such as better DER location selection, streamlined DER interconnection processes, flexible interconnection options, reductions in time to interconnect, and better customer and third party information sharing and services. By reducing costs and other barriers to interconnect, grid modernization will help more Rhode Island customers invest in their own DER technologies in areas where these technologies are most cost-effective. **In addition, AMF will provide more granular energy usage data to enable customers to better understand and choose among DER offerings (i.e., DG, storage, EV, DR, and EE solutions) to better manage their energy usage and costs.** Specifically, GMP investments will facilitate cost-effective customer investment in DERs by enabling: • Load optimization to relieve thermal or voltage constraints due to DER adoption rather than relying on traditional "wires-based solutions" • Improved efficacy of EE and DR programs by providing more granular data to customers (e.g., detailed billed energy use, in-home displays); • Third-party programs and offerings that will drive innovation and provide additional value to customers, while encouraging new industry participants to enter the market with new customer offerings; • Savings on EV charging costs by virtue of future TVR that incentivize customers to displace vehicle charging to off-peak times; • Higher hosting capacity on the distribution system to accommodate higher penetrations of DERs at lower cost; and • More cost-effective DER investment due to system information sharing via the system data portal. In the future, **DERMS, in combination with an ADMS and other GMP investments including AMF, will enable optimization of DER output (e.g., reduced DER curtailment) and provide the necessary information, operations and settlement services to DER providers, which are required to efficiently integrate DER into the delivery system**.

Table 4-3: Alignment of GMP Investments with Docket 4600 Goals

Goals For "New" Electric System	Advances? /Detracts From? /Is Neutral To?
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Advances: The GMP investments are necessary to assess the locational and temporal value DER may provide to the electric system. In the near-term, grid modernization will help identify and fairly compensate non-wires alternative (NWA) projects. **In the longer term, grid modernization, combined with new DG tariffs and TVR enabled by AMF, could more directly and accurately compensate DERs for their value.**
Appropriately charge customers for the cost they impose on the grid	Advances: The GMP does not propose utility revenue requirements, cost allocation or rate design at this time. However, per the ASA, this Updated AMF Business Case includes assumptions to develop a future TVR proposal in a separate docket. **AMF, in combination with TVR and other GMP investments, will enable new pricing and allocation mechanisms to attribute costs and benefits more equitably**.
Appropriately compensate the distribution utility for the services it provides	Advances: The ability to monitor two-way power flows will allow the Company to better understand the impacts of DER and assess the value that the grid provides to both consumers (i.e., ratepayers) and producers (i.e., DER customers) and with this enhanced understanding, the Company should be better positioned to develop innovative and appropriate rates.

Table 4-3: Alignment of GMP Investments with Docket 4600 Goals	
Goals For "New" Electric System	**Advances? /Detracts From? /Is Neutral To?**
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives	Advances: The GMP includes a detailed BCA that is aligned with the Docket No. 4600 regulatory framework in order to better align distribution utility, customer, and policy objectives. In addition, specific GMP investments like the System Data Portal will provide transparency concerning system needs and opportunities for interested stakeholders, thereby fostering a more collaborative approach to distribution system planning and operations. **AMF provides improved customer data access through the CEMP and HAN, as well as facilitating easier data sharing among customers and third parties using GBC.[63] It also enhances existing customer programs in EE, DR, and EVs as outlined in the CEP. When coupled with future rate designs and incentives, AMF also aligns customer and utility interests with policy objectives by providing customers with greater choice and control over energy usage while providing the Company with better visibility of its distribution system, leading to a cleaner, more efficient electric distribution grid.** Finally, stakeholder engagement has been a large component of the GMP and AMF filings and through this forum, the Company and stakeholders have worked to ensure customer and policy objectives and interests are addressed. Through the GMP, this Updated AMF Business Case, and future regulatory filings, the Company will continue to align grid modernization with customer, distribution utility, and policy objectives and interests.

[63] *See* Section 7 for descriptions and other details about CEMP and GBC.

5. Metering Technology Solution Screening and Detailed AMF Roadmap

This section describes the technical solution that is best suited to achieve the required grid modernization capabilities described in Section 4. The Company evaluated the relative merits and cost effectiveness of a variety of customer-, grid-, and meter-level technology solutions. The recommended solution is outlined in additional technical detail, including the planned timeline for the delivery of AMF (AMF Roadmap) and how that functionality is critical to achieving GMP objectives.

5.1. Screening Metering Solutions

The current AMR meter assets deployed in the Rhode Island service territory are soon approaching the end of the manufacturer's estimated useful life. This provides the Company with an opportunity to not simply replace the current asset portfolio with in-kind technology, but to evaluate the various options and functionalities that will support next-generation metering in Rhode Island. As a first step in this process, the Company identified and compared metering technology solutions and complementary customer and grid technologies on a functionality basis to determine the options that meet the capability requirements of a modernized grid. The options and functionality assessment reflect input from metering experts and the Subcommittee. During the second step of the process, the Company considered the relative economics of the viable options identified in step one. Below is a brief description of the metering technology solutions (customer- and grid-facing) the Company evaluated:

- **Current AMR**: The electric AMR meters contain either a single or triple communication module configuration where each such module supports the transmission of a single billing determinant. The Company uses a drive-by meter reading vehicle to retrieve meter data through short-range radio frequency (RF) signals emitted from the AMR devices. AMR meter technology supports the monthly collection and processing of customer metering data. On a limited basis, approximately 1,200 triple communication module configuration AMR meters are deployed to support basic time-varying and demand rates today. The triple communication solution provides a technical limitation in that no more than three energy measurements (i.e., TOU periods) can be collected; this technology is outlined in additional detail in the "Targeted Enhanced AMR" section below. Gas metering technology only supports the installation of a single, battery powered, AMR communication module, which provides a single billing determinant. Although AMR technology is mature, having been broadly deployed for decades across the United States, it has increasingly been replaced by AMF deployments, which are better suited to support innovative energy policies and grid modernization objectives.[64]

[64] *See* Section 3.3 for additional detail on the current technical AMR solution.

- **Targeted Enhanced AMR**: This option would expand the current AMR solution by implementing targeted deployment of additional triple communication module electric AMR meters. The additional enhanced AMR devices would be deployed to support expanded (basic) time-varying and demand rates. The solution would require each meter to be manually re-programmed any time the PUC implements or modifies TVR, or a customer decides to change his or her TVR enrollment. This limits the ability for the PUC and customers to be agile in the adoption of innovative rate structures, while also creating a significant cost burden due to the requisite reprogramming field visit. Additionally, a triple communication AMR meter is 2 to 3 times more expensive than an AMF meter, and an added operational cost for meter reprogram/replacement that is equivalent to that of installing a new meter. This targeted option would only be used to implement specific utility programs on a limited or opt-in basis to support time-varying and demand rates. As such, the Company determined that targeted enhanced AMR (i.e., triple communication module) is cost prohibitive to utilize as a technology platform, based on meter and operational costs.

- **Targeted AMF Deployment**: A targeted deployment of cellular-based AMF meters can be deployed to support enhanced customer benefits. The Company leverages this solution today to support a subset of Rhode Island's G32 customers (less than 300 customers) and would need to be enhanced to support additional meter end points. It is likely that as DER saturation increases and related interval measured tariffs evolve, customers enrolled in the associated programs will be required to have an interval read AMF meter. In the absence of full-scale AMF deployment, which would provide sufficient geographic meter deployment to support a RF mesh network, the Company will continue to deploy the cellular technology necessary for new applications that require interval meters. This is the key technical difference between this solution and the full-scale AMF deployment alternative described below. A combination of a smaller geographic meter density and inability of peer-to-peer meter communication reduces the current and future functionalities enabled by cellular AMF as compared to full-scale AMF deployment. This solution would be integrated to customer systems, including billing and the CEMP, to provide energy usage data access, insights, and service offering to enable enhanced customer energy management. Furthermore, a targeted solution would only be available on the gas side for dual-commodity customers who have a cellular AMF metering device.

- **Full AMF Deployment**: A comprehensive, full-scale AMF solution, involves the deployment of smart meters to all customers in Rhode Island. An integrated advanced metering network (RF mesh network) will be implemented to support electric and gas AMF devices throughout the service territory. The broad deployment supports maximum functionality and adaptability of the intelligent computer platform residing in metering devices, along with peer-to-peer communication, data analytics and integration with third-party devices. Similar to the targeted AMF deployment solution, full-scale AMF will integrate with customer and billing platforms, as well as the CEMP, to provide energy usage data access, insights, and service offerings to enable enhanced customer energy management.[65]

- **End-User Solutions**: Customers can procure and install devices in their home that offer insight and enhanced granularity regarding their energy consumption and usage patterns. A wide variety of technical solutions exist in the market such as high-resolution home sensors (e.g., Sense) and in-home technology energy management packages (e.g. Nest, Alexa, etc.). A key limitation of these solutions involves the absence of interconnectivity and integration with the Company's customer and billing systems, as well as the CEMP, resulting in isolated, standalone third-party solutions. Although this technology can enable enhanced customer functionality such as load disaggregation, these solutions cannot provide revenue-grade billing determinants and they do not meet ANSI energy measurement standards. Additionally, these solutions can be costly to deliver, while providing a small subset of full AMF functionality and integration. Future technology advances in end-use solutions may ultimately provide revenue-grade metering;[66] however, it is highly uncertain whether they will be cost-effective alternatives to AMF.

- **Transformer-Level Sensor**: Across the distribution system, sensors are strategically placed to support a variety of grid modernization functionality such as locational awareness/GPS, while also collecting granular, time-aligned voltage and current data. This allows the Company to better regulate voltage on the transmission system, receive outage notifications and support current and potential transformer analysis.

- **Pole-Top Reader**: This technology leverages a combination of standard and enhanced AMR technology, replacing drive-by meter reading vehicles with remote AMR meter reading radios. A pole-top reader can support the enhanced meter reading frequency of the AMR devices, but remains limited to meter register readings and does not provide the same level of functionality and data delivery as AMF.

As illustrated in Table 5-1, the Company compared functionality of the various solutions. Comprehensive AMF functionalities, which are described in Section 5.3.1, provide the basis for the solution comparison. The comparison demonstrates that only targeted AMF and full-scale AMF, provide the wide range of functionality for customers. Although the targeted AMF option offers similar customer-facing functionality to full AMF, it possesses significant limitations regarding grid-facing functionality due to geographic meter saturation limitations and the loss of peer-to-peer communication and related distributed intelligence capabilities as compared to full AMF.

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[65] *See* Section 5.2 for a detailed description of the full-scale AMF solution.

[66] *See e.g.*, Green Mountain Power, *GMP Pioneers Patent-Pending System Using Energy Storage to Make Meters Obsolete* (April 30, 2019), https://greenmountainpower.com/news/gmp-pioneers-patent-pending-system/

As illustrated by the table, the current AMR technology is a limited purpose solution. It was implemented in the early 2000s to replace manual meter reading processes and generated timelier and more accurate meter reads for traditional rate design billing. The solution has been utilized in a limited manner to support simple TVR and could be extended to additional customers as described in the Targeted Enhanced AMR solution described above. However, the AMR technology options do not provide any of the customer-facing functionalities that enhance customer energy management or the grid-facing functionalities that support the improved system operations, planning, and DER integration required in a modernized grid. Additionally, the AMR metering assets are reaching the end of the manufacturer's estimated useful life, requiring significant investment to replace exist AMR metering devices with in-kind technology in the near term.

Additionally, customer- and grid-facing technologies can provide a subset of the full-scale AMF functionalities, but are not a viable alternative to an AMF metering solution; notably, such solutions cannot deliver revenue-grade interval meter reading data. Not only do these technology platforms drive increased customer costs, investment in these solutions does not address the need to replace the existing AMR meters.

The Company's functionality analysis has identified AMF metering as the only fit-for-purpose solution to meet the objectives and capabilities for a modernized grid. A screening analysis regarding targeted and full-scale AMF solutions was performed to estimate the benefit and cost implications of each program. Based on the screening analysis, the Company determined that targeted deployment avoids only a fraction of total AMF costs, while presenting a significant reduction to the anticipated program benefits. As a result of the screening analysis and the poor cost/value proposition for the targeted AMF solution, the Company does not believe it is a viable metering option. Appendix 10.2 expands on the Company's approach and associated results of the screening analysis.

Table 5-1: Functionality assessment of metering solutions and customer and grid technologies.

	AMF Functionality/Use Case	Complete Metering Solutions				Complementary Customer and Grid Technologies		
		Current AMR	Targeted Enhanced AMR (for opt-in TVR)	Targeted AMF*	Full AMF	End User Solutions**	Transformer-Level Sensor	Pole-Top Reader***
Customer-facing	CEMP – Near Real Time Customer Data Access	○	○	●	●	●	○	○
	CEMP – Customer Energy Insights	◑	◑	●	●	◑	○	◑
	CEMP – Bill Alerts	○	○	●	●	◑	○	◑
	CEMP – Load Disaggregation	○	○	●	●	●	○	○
	CEMP – Green Button Connect	○	○	●	●	○	○	◔
	Integration w/ In-Home Technologies	○	○	●	●	●	○	○
	Time Varying Rates - Customer & DER	○	◔	●	●	○	○	○
	Remote Interval Meter Reading	○	○	●	●	○	○	○
	Remote Meter Configuration	○	○	●	●	○	○	○
	Remote Meter Investigation	○	○	●	●	○	○	○
	Remote Electric Connect and Disconnect	○	○	●	●	○	○	○
	Theft Detection	◔	◔	◕	●	○	○	◔
Grid-facing	Voltage Measurement – Voltage Conservation	○	○	◔	●	○	◑	○
	Outage Detection – Automated Notification	○	○	◔	●	○	◑	◔
	Time Varying Rates – Load Shift	○	○	◕	●	○	○	◔
	Load & Voltage Data – Situational Awareness/Forecasting	○	○	◔	●	○	◑	◔

*Harvey Balls for Targeted AMF indicate functionality enabled for customers who adopt AMF meters, not the entire population

**Includes combinations of high-resolution home sensors (e.g., Sense) with in-home technology packages (e.g., Nest, Alexa, etc.) and no integration with CEMP or company systems.

***Assumes integration with utility platform services (e.g., billing)

In addition to the functionality comparison in the table, the BCA presented in Section 8 provides the cost of replacing AMR meters with new AMR meters when they reach the end of their 20-year useful life. The AMF BCA fundamentally outlines the incremental benefits AMF can achieve compared to the AMR solution, while defining the cost differential required to implement full-scale AMF. The cost of AMR replacement is treated as an avoided cost in the AMF BCA analysis, because in lieu of an approved AMF program the Company would be required to replace the AMR assets. The BCA results in Section 8 demonstrate that full AMF deployment has a significantly stronger cost-benefit value as compared to an AMR replacement program.

5.2. Full AMF Option Technical Solution Description

The AMF technical solution includes four key advanced metering elements, as illustrated in Figure 5-1 below: 1) an integrated RF peer-to-peer (mesh) network of smart electric meters and gas modules capable of capturing customer energy usage data at defined intervals and supporting grid-edge applications; 2) a two-way communications network and related IT infrastructure for transmitting the data and control signals utilizing mesh and cellular communications technology; 3) an integrated HES, MDMS, IT platform, and cybersecurity protocols to securely and efficiently collect, validate, store and manage the meter data; and 4) customer systems including billing and the CEMP to provide energy usage data access, insights, and service offerings that enable customer energy management.

At the end-point level, the Company is proposing AMF technology that will capture and transmit energy usage data (15-minute intervals every 30 to 45 minutes for electric and one-hour intervals every eight hours for gas) through a RF mesh or cellular communications network. This same information can also be communicated to in-home/business and mobile devices directly from the electric meter. A series of gateway devices are strategically placed throughout the service territory to collect meter data and transmit the data through a backhaul network to the Company. The HES then processes the data before it is transmitted to the MDMS, which performs data validation and generates the appropriate billing determinants for each customer. This data will be processed by the Customer Service System (CSS) for billing and delivered to the CEMP, which provides customers and authorized third parties with access to energy consumption data, energy insights, and service offerings.

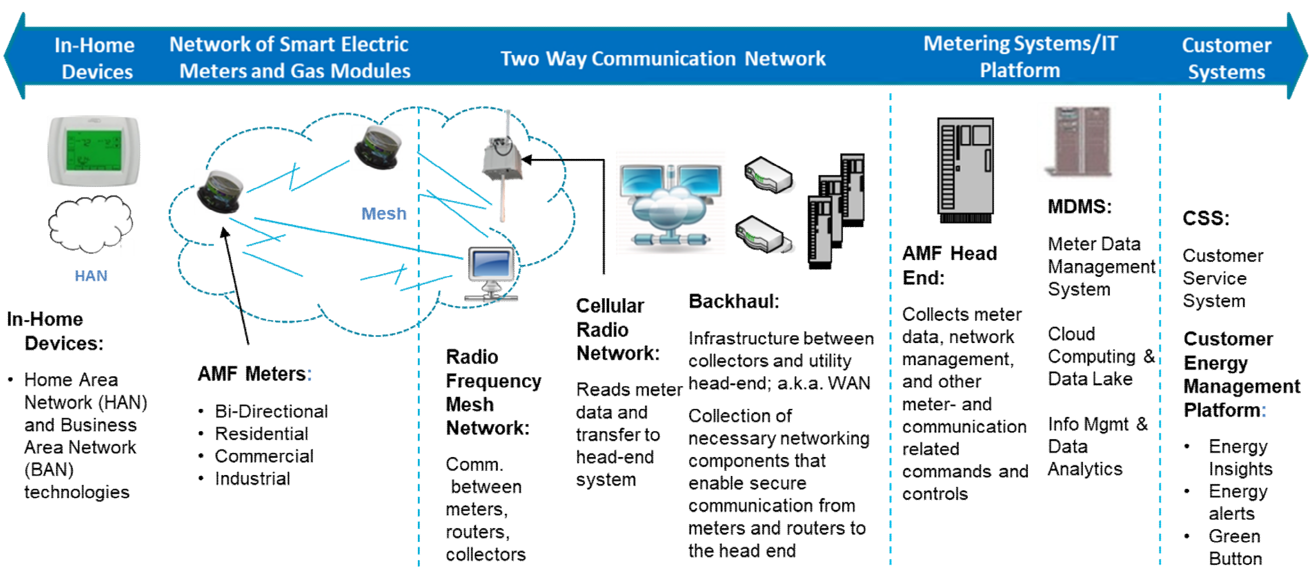


Figure 5-1: AMF Technology Elements

One of the key design considerations is "data latency," which, in an AMF solution, refers to the time delay from when a meter or end-point captures data to when the information is available to a customer or authorized third-party service provider. With the evolution of energy services, customers and third parties are no longer satisfied with simply accessing granular data; now, the timeliness and availability of the energy usage data is of growing importance to support DR, TVR, and enhanced customer education and energy management.

The Company's AMF proposal provides access to energy usage information for all customer classes through three primary channels: 1) the CEMP; 2) facilitating data sharing with authorized third parties using GBC, which will be accessible from the CEMP; and 3) directly from the meter through a HAN. The first two channels, the CEMP and GBC, require meter usage data transmission from the meter, through the end-to-end AMF solution, to the data sharing platforms in the CEMP. Through this data process, the Company proposes to provide access to 15-minute raw electric energy usage data at 30 to 45-minute latency and hourly gas intervals at an eight-hour latency. Customers will have access to the CEMP through the web and mobile devices. The HAN, the third channel, provides optionality for customers to obtain real-time usage data directly from the meter. Electric AMF meters contain a physical radio and associated firmware to provide a wireless signal to HAN devices for data transmission. Similar to how devices are connected in homes today through a wireless router, meters can be paired[67] with in-home devices that customers or third parties deploy to share and display customer data in real time. Customer data can also be made available to customer mobile devices, leveraging HAN and third-party internet-based service offerings. A description of data access channels and latency parameters is provided in Table 5-2.

[67] For a customer to connect a HAN-related device to an AMF meter, the customer will first confirm the eligibility/compatibility of the device with the AMF meter and then activate the device by logging into their secure online account on the CEMP. Once logged in, the customer will navigate to the activation page, enter the applicable device credentials, and receive an activation acknowledgment through encrypted channels. From there, the customer may begin using the HAN device, such as an in-home display or home energy manager.

Table 5-2: Customer Data Access Latency

Data Access Channel	Description	Data Latency
Customer Energy Management Platform (CEMP)	Customers can access their own usage data directly and download it to share with third parties.	• For electric customers, 15-minute raw interval data will be available every 30 to 45 minutes. • For gas customers, one-hour raw interval data will be available every eight hours. • Bill quality[68] data will be available every 24 hours.
Green Button Connect (GBC)	Facilitates computer-to-computer communication to allow for a standard protocol by which customers can provide authorized third parties direct access to energy usage data.	
Meter to Home-Area-Network (HAN)	Transmits data directly from meter to HAN.	• Real-time raw energy usage data.

The above channels with their respective data latencies support the customer-facing functionalities and related benefits outlined within this business case. The channels also support a variety of grid-facing functionalities and related benefits where lower data latency may be required. Table 5-3 categorizes the AMF functionalities that are dependent on customer data and the required latency. In addition, the Company has included data latency benchmarking information from peer AMF implementations in Appendix 10.3.

[68] To generate "bill quality" data, a series of validation, estimation, and editing (VEE) functions are performed on the raw data.

Table 5-3: AMF Customer Data Access Latency Requirements

	AMF Functionality	Data Latency Requirements	
		Standard	Real-Time
Customer - Facing	CEMP - Near Real-Time Customer Data Access	X	
	CEMP - Customer Energy Insights	X	
	CEMP - Bill Alerts	X	
	CEMP - Load Disaggregation	X	X
	CEMP - GBC	X	
	Integration w/ In-Home Technologies		X
	TVR - Customer & DER	X	X
	Remote Interval Meter Reading	X	
	Remote Meter Configuration	N/A	
	Remote Meter Investigation	N/A	
	Remote Electric Connect and Disconnect	N/A	
	Theft Detection	X	
Grid-Facing	Voltage Measurement - Voltage Conservation	X	X
	Outage Detection - Automated Notification	N/A	
	TVR - Load Shift	X	X
	Load & Voltage Data - Situational Awareness/Forecasting	X	

In addition to displaying usage data through a HAN or business-area network, home energy management systems will be able to receive and send secure communications from the Company or third-party market entities. This can enable real-time customer access to meter data, including load/price signals and real-time integration with smart devices such as thermostats, water heaters, and other appliances. These enhanced service opportunities will be promoted on the CEMP.

Another key design attribute of the AMF solution is the flexibility and adaptability of the solution to meet evolving customer and grid needs. The solution the Company proposes to implement represents the latest generation of maturing AMF technology;[69] its capabilities include over-the-air firmware upgrades and grid-edge computing platform functionality. Supporting software applications will be deployable to the meters for both grid- and customer-

[69] *See* Gartner Report, *Hype Cycle for Smart Grid Technologies*, ID: G00314513 (July 31, 2017).

facing use cases ranging from integration of additional DER and EVs on the grid to providing more choice, conveniences and control through additional information.

The Company believes the grid-edge computing platform will enable significant future customer- and grid-facing capabilities as described in the AMF Roadmap (Section 5.3). The Company will also work with stakeholders and third parties to identify and consider new capabilities to ensure that evolving customer and grid needs continue to be met in the future.

5.3. Roadmap for AMF-Enabled Functionalities

This section lays out the various AMF-enabled functionalities, the associated costs of the functionalities, and a timeline for when the Company anticipates the functionalities will be deployed. The cost and benefits of the functionalities enabled by the initial AMF implementation are included in this business case. Future functionalities are split into two groups, those that could occur in 5-10 years and those that will be potentially available in greater than 10 years. These future functionalities are described to demonstrate how the AMF solution is flexible, adaptive, and can evolve over time to meet future needs. The functionalities are in the early stages of industry development and testing. The Company expects the future functionalities will require additional evaluation and funding over the next 20 years.

Table 5-4: AMF-Enabled Functionalities, Funding, and Timeline

Deployment Timeline	Description	Costs Included in Business Case?
Near-Term Functionalities Available Upon Deployment	Functionalities enabled by initial AMF implementation; all associated benefits and costs included in this Updated AMF Business Case.	Yes - All costs included in Updated AMF Business Case and accompanying BCA.
Future Functionalities (5-10 years)	Future functionalities in various stages of development and testing by AMF vendors that will require additional evaluation and funding.	No - Qualitatively discussed in this Updated AMF Business Case, but costs and benefits are *not* included in accompanying BCA. These functionalities would be proposed in future filings if and when they are deemed beneficial to Rhode Island customers.
Future Functionalities (>10 years)		

5.3.1. AMF Near-Term Functionalities and Roadmap

As shown in Table 5-5, several AMF near-term functionalities are included in the first five years of this Updated AMF Business Case and are reflected in the AMF BCA.

Table 5-5: AMF Near-Term Functionalities

Functionality	Description
CEMP - Near Real-Time Customer Data Access	Raw usage data available at standard latency (30-45 minutes for electric data; 8 hours for gas data).
CEMP - Customer Energy Insights	Customer-facing usage data availability, usage analytics, normative comparisons, and other data-driven customer experience features. Provide omni-channel access and continuous improvement through an agile and iterative development approach that incorporates on-going customer experience updates.
CEMP – Bill Alerts	Alerts for variety of customer needs. Examples include projected high-bill (consumption and/or costs), prediction of peak demand or usage, and customizable threshold alert at various points during a billing period.
CEMP - Load Disaggregation	Grid-Edge Computing Application: Provides a breakdown of electricity consumption by appliance or end-use to educate customers and to provide recommended energy-saving actions – available through the CEMP.
CEMP – GBC	Enables customers to provide for the automated transfer of customer energy usage data at standard latency to authorized third parties.
Integration w/ In-Home Technologies	Ability to connect the meter to in-home/in-business technologies to communicate information and control signals.
TVR - Customer & DER	Develop TVR billing capabilities (e.g., determinants, bill formats).
Grid-Edge Computing	Metering platform for customer- and grid-facing software applications.
Voltage Measurements	All electric meters at standard latency.
Outage Detection	Meter power on and off status.
Remote Interval Meter Reading	Interval energy usage meter reading at standard latency.
Remote Meter Configuration	Remote "over-the-air" firmware and software updates.
Remote Meter Investigation	Investigate meter malfunctions.
Remote Electric Connect and Disconnect	Activation of remote electric meter switch to turn on/off service.
Theft Detection	Meter tamper alerts and usage analytics.

The AMF-enabled functionality roadmap in Figure 5-2 illustrates when each of the near-term functionalities will be developed and implemented. Except for TVR and Outage Detection, the Company proposes to develop and implement the functionalities when meter installation begins in project year 3. Although TVR functionality will depend on regulatory approval of a TVR structure, this business case provides an illustrative timeline with TVR approved and developed prior to meter installation. Actual TVR implementation, however, is expected to lag customer meter installation to permit customers a gap year before TVR would become effective. The gap year is intended to help customers get familiar with their new meter and understand the new interval usage information and pricing options. The timeline and detailed TVR program will be subject to consideration by the PUC in a separate docket. AMF outage detection integration with the Company's restoration systems and processes will also lag meter deployment to provide time for the Company to design and test the integration with actual meter outage information.

	AMF Functionality	Timeline			
		Year 1	Year 2	Year 3	Year 4
Customer Facing	CEMP - Near Real Time Customer Data Access				
	CEMP - Customer Energy Insights				
	CEMP - Bill Alerts				
	CEMP - Load Disaggregation				
	CEMP - Green Button Connect				
	Integration w/ In-Home Technologies				
	Time Varying Rates - Customer & DER				
	Remote Interval Meter Reading				
	Remote Meter Configuration				
	Remote Meter Investigation				
	Remote Electric Connect and Disconnect				
	Theft Detection				
Grid Facing	Voltage Measurement - Voltage Conservation				
	Outage Detection - Automated Notification				
	Time Varying Rates - Load Shift				
	Load & Voltage Data - Situational Awareness/Forecasting				
Shared GMP & AMF Enabling IT Infrastructure	Operational Telecommunications				
	Cybersecurity				
	Operational Information Management				
	Grid Edge Computing				

Legend
Development
Implementation

Figure 5-2: AMF-Enabled Near-Term Functionality Roadmap

5.3.2. AMF-Enabled Future Functionalities

As shown in Table 5-6, the near-term functionalities will likely lead to the development of AMF-enabled future functionalities capable of delivering additional benefits. The Company divided these potential future applications into two groups: 1) those functionalities that may be available in 5-10 years; and 2) those functionalities that are on a longer development path (i.e., greater than 10 years). In addition, Table 5-6 links these potential future functionalities to near-term enablers. For example, the future functionalities described in Table 5-6 would utilize the grid-edge computing platform capabilities enabled by near-term AMF functionalities that support deploying software applications to the meters for both grid- and customer-facing use cases. The future functionalities are based on the Company's evaluation of the AMF vendors' solution capabilities and development roadmaps as part of the competitive RFS process described in Section 7.3.6. The Company will further evaluate the future functionalities (e.g., proof of concept) as the Company implements the AMF solution. To the extent the functionalities merit implementation, the Company will include incremental funding requests and justification, as appropriate, in future rate proceedings.

Table 5-6: AMF-Enabled Future Functionalities

Functionality	Description	Technology Dependencies	Timetable
Grid Mapping/Locational Awareness	Algorithms allow meters to define their location at a transformer and feeder level to better collate GIS data while providing enhanced insights to load forecasting, voltage and outage management systems.	Grid-edge computing application, integration with GMP functionalities	5-10 years
Enhanced Load Disaggregation	Provide customers with real-time energy monitor and real-time device-level breakdown with access to real-time alerts	Grid-edge computing application with HAN integration	5-10 years
Bypass Theft Detection	Theft detection uses real-time, high resolution analysis of data from power flows rather than anecdotal alarms and alerts to detect customer energy theft through meter tamper/bypass as well as direct connection of loads to the low-voltage wiring.	Grid-edge computing application	5-10 years
Intelligent Voltage Monitoring	Intelligent Voltage Monitoring enables voltages on the distribution network to be analyzed at the meter level, to optimize the asset life of transformers while ensuring power delivery at acceptable voltage ranges and power quality standards. Exceptions are reported.	Grid-edge computing application	5-10 years
Distributed Outage Detection	Analytics are performed at the meter to identify power on/power off signals along with voltage data to quantify power outages for segments of the distribution system, which are then integrated into an OMS to support service restoration.	Grid-edge computing application, OMS integration	5-10 years
Temperature monitoring	Detecting a rise in temperature in a meter socket can alert utilities prior to a potential fire or possible over-heating concern.	Grid-edge computing application	>10 years
Arc sensing	Electrical arc sensing on both the customer- and grid-facing components supports safety and reliability benefits by proactively identifying anomalies and unsafe conditions.	Grid-edge computing application	>10 years
High-Impedance Detection	Identification of high-impedance points in the distribution network, including at the meter, which can result in voltage complaints, connection failures, and even fire in some cases.	Grid-edge computing application	>10 years

Table 5-6: AMF-Enabled Future Functionalities

Functionality	Description	Technology Dependencies	Timetable
Broken Neutral Detection	Detects broken neutral and poor ground conditions as they are developing on the customer side of the transformer so that potential safety problems can be identified and corrected as quickly as possible.	Grid-edge computing application	>10 years
Active Demand Response	Autonomous demand management locally and intelligently by integrating with customer HAN devices to support demand reduction in accordance with utility demand events. Integration with EV charging stations can provide additional demand benefits while facilitating electrification.	Grid-edge computing application with HAN integration	>10 years

Beyond the items listed above, the Company believes data analytics is an area expected to provide additional functionality in the future. As the industry continues to evolve, the number and types of data analytics use cases, as well as the extractable value of available data from grid-edge devices (i.e., meters and sensors), will continue to increase. Using data analytics, the Company can turn this data into actionable insights, increasing benefits for customers and core utility business functions. Potential use cases include improved mapping capabilities, distribution planning and asset management, EV functionality, and DER adoption/deployment.

5.3.3. Integration of Other End-Point Devices

The AMF communications network and back-office systems can be leveraged over time to integrate other end-point devices to provide additional customer value that is not quantified in the BCA. The Company is open to exploring the use cases in ongoing and/or future forums with the PUC and interested stakeholders. As stated in the Metrics and Performance Incentive Measures Roadmap (Attachment D), execution of these and/or other new functionalities that demonstrate ongoing utilization of the AMF network and are BCA positive could be the subject of future PIMs. A non-exhaustive list of future opportunities is included below.

Water Utility/Municipality Revenue Opportunities with Joint Use

Water utilities could leverage the technical umbrella of the Company's proposed AMF infrastructure to support overlapping metering efforts, offering a "Metering-as-a-Service" to interested jurisdictions. The Company's platform could serve as the wireless FAN, backhaul, and back-office validation systems for a smart water metering capability.

AMF for Street Lights and Ancillary Devices

The integration of AMF metering, wireless communications, and lighting control technology have fostered an expanding array of ancillary device deployments in support of customer-centric services. Many vendors have developed proprietary platforms that combine a photoelectric control having dedicated solid-state AMF chip-meter technology and varied forms of wireless communication modes incorporated within a small form-factor for use in conjunction with street lighting infrastructure. The advent of these collective technologies was initially promoted by the EE and environmental benefits achievable through remote controlled light emitting diode (LED) technology applications in street lighting. The opportunity for customer specified operating schedules was further enabled by using the AMF metering for the energy consumption measurement of the individual street light. This advancement would allow the lighting control device to integrate with the AMF electric metering mesh network to transition street lighting from an unmetered to a metered billing application. Additionally, the lighting control devices provide electric power quality monitoring, operational performance, maintenance diagnostics of the luminaire, GPS, structure inclination and other lighting system data unavailable without a site investigation assessment.

The further advancement of these technologies has been expanded within the street lighting industry and other business use cases under the “Smart City” moniker. The small form factor and wireless communication capability in conjunction with the availability of electric service voltage on potential vertical real estate has fostered a ground swell of innovative and complementary applications. These combined technologies have included video streaming, asset detection (e.g., license plate reader, parking management), environmental sensors (e.g., climatology, pollution and hazardous chemicals), gunshot detection, traffic management, emergency services, waste management and other internet of thing (IoT) devices. Additionally, the control and metering capabilities are considered the prospective solution to managing the expansive deployments of community Wi-Fi applications, EV charging facilities, and mobile communication infrastructure (e.g., 4G LTE and 5G). The Company’s proposed communications infrastructure and potential back-office systems could be leveraged to support network services to interested third parties.

However, as identified and reported by the Company in Docket No. 4513, the metering and lighting industries continue to address the need for established industry standardization of meter accuracy testing and application performance criteria. Additionally, the adoption of uniform industry communication standards for this technology segment will minimize the limitations imposed by proprietary protocols, further expanding interoperability and end-use opportunities.

“Smart” Gas Meters

Advancements in meter technology have developed gas meters with multiple safety functionalities, including temperature sensing, overpressure protection, excess flow monitoring, and air-detection tamper alerts. Each of these attributes will trigger the meter to potentially shutoff gas to prevent emergency situations from occurring. The smart gas meters also can shutoff gas to the customer proactively through the AMF network if an external safety event is occurring nearby, such as a fire, gas leak or other unplanned emergency. Having the AMF mesh network in place enables Rhode Island and the Company to advance this emerging technology quickly to enhance customer safety as smart gas meters become available. Smart gas meters require back-office integration to enable full end-to-end operability.

"Smart" Residential Methane Detectors

Residential methane detectors (RMD) equipped with communication devices, also known as smart residential methane devices, are currently in research and development for AMF deployment. In the event the smart RMD senses methane at a customer location, it would be able to send a notification to the Company through a fixed communication network, expediting the Company's response even if a customer has not called to report the issue.

Gas TVR and Demand Response

Historically, discussions of TVR have focused on electricity. Gas markets lack the temporal resolution to pass signals through to rates. However, in the future, sub-daily gas rates may be used to create financial signals for customers to efficiently use the gas system. Sub-daily usage is already measured for system operations, which can impact the terms of supply contracts. In addition to making sub-daily rates feasible, an increase in temporal resolution of gas system data would support the expansion gas DR.

The Company and its affiliates are currently engaged in several gas DR programs or pilots. Data is a critical component of those efforts. To capture the data, the Company has installed supplemental metering to gather the necessary information regarding customer participation. If AMF was available, the programs could be deployed more efficiently, as there would not be a need for supplemental metering. Also, AMF could potentially allow for additional tiers of participation in the programs/pilots providing flexibility for customers. One learning from the DR pilots is that customers assign a significant value to having access to granular usage data. Many of the participants in the programs have stated that this has more value to them than the incentives they receive.

One of the Company's downstate New York affiliates was the first utility in the country to explore incentivized gas DR for firm C&I customers as part of a pilot that began in 2017. The pilot will run for three years and includes 16 facility-participants with a goal of shifting gas load outside the peak hour (i.e., changing the shape of the load profile). Events within the pilot are called for three hours between 6 a.m. and 9 a.m. from December through March. The pilot was approved as part of the affiliate's 2016 rate case and the company was awarded the inaugural Utility Industry Innovation in Gas award by the National Association of Regulatory Utility

Commissioners (NARUC). Additionally, the Company's downstate New York affiliate launched both incentivized Bring Your Own Technology (BYOT) and non-incentivized behavioral residential and small-and-medium business (SMB) gas DR programs for winter 2019-2020.

Though same-day incentivized gas DR programs are a relatively new offering, tariffed rates that create peak-day reductions via customer behavior have been a critical component of system planning and design for many decades. Specifically, National Grid and its affiliates have operated both interruptible (customer-controlled curtailment for events called at the utility's discretion) and temperature-controlled (utility-controlled curtailment for events initiated based on air temperature) rates for large C&I customers. Nearly 3,000 customers are on these rates in downstate New York. However, based on the market response for the DR pilot, the Company's affiliates proposed expanding their DR portfolios in downstate New York as part of their pending rate case with a modified version of the current DR program and two new programs to reach the SMB and residential classes. Customer participation in the rates requires additional metering to track usage and, if necessary, calculate bills for non-compliance. Full-scale AMF deployment would enable wider rollout of similar programs in Rhode Island without requiring additional metering. Also, the presence of more granular usage data from AMF would facilitate program deployment and evaluation, helping the Company better understand usage and reward customers.

In addition, another Company's affiliate has partnered with Fraunhofer Center for Sustainable Energy Systems to conduct a pilot in Massachusetts. The Company is also piloting two DR programs in Rhode Island – a short event program called Peak Period Demand Response (three-hour events) focusing on daily peak, and a longer event program called Extended Demand Response (24-hour events) focusing on reducing daily load. There are currently two facilities participating in the Peak Period Demand Response program, and one facility participating in the Extended Demand Response program.

Improved Gas Reliability

Integration of gas end-point devices into the AMF network will improve forecasting, response to events, and the scale at which DR could be deployed in the gas distribution system. Accuracy and efficiency of long-term and emergency planning processes are improved when informed by high-resolution data. Event tracking and interruption isolation would benefit from high-resolution data combined with smart meter sensing and an ability to remotely disconnect service. And as already mentioned, AMF would enable gas DR, which could reduce peak demands and mitigate high- or low-pressure conditions to prevent interruption events.

5.4. <u>AMF Health Considerations</u>

The Company is committed to providing safe, reliable service to its customers and ensuring that health concerns are fully addressed. The Company also recognizes that many Rhode Islanders will naturally be wary of having new technologies installed in or near their homes and businesses. For example, smart meter solutions in other states have previously generated concerns around RF exposure.[70] The Company has conducted research across government organizations, scientific studies, industry groups, consumer education non-profits, and court rulings, all of which have concluded that the low-level frequency produced by smart meters poses no credible health or safety threats to consumers. These findings are summarized below, and further detail can be found in the links presented at the end of this Section.

Government Organizations

Every day, people are exposed to low levels of RF energy, from natural sources, such as the sun, the Earth and the Earth's outer atmosphere, and from man-made sources, such as telecommunications and common electronic devices like cell phones or microwaves. The Federal Communications Commission (FCC) requires testing of all wireless communications devices to ensure they meet minimum guidelines for safe human exposure to RF energy before allowing the devices to be used.[71] The smart meter technology the Company proposes to use is no different. All smart meters installed by the Company's affiliates as part of the Worcester Pilot and Clifton Park Demonstration, as well as those proposed to be installed as part of this business case, have followed or will follow the FCC process, certifying the meters are safe and comply with applicable government safety standards.

Scientific Studies

The existing scientific research supports the assertion that smart meters are safe for consumers. In 2010, the California Council on Science and Technology (CCST) received a request from the California Assembly to perform an "independent, science-based study" to help policymakers and the public resolve the debate on smart meter health risks. The CCST's final report in 2011 concluded: 1) "the FCC standard provides an adequate factor of known RF induced health impacts of smart meters;" and 2) "there is no evidence that additional standards are needed to

[70] *See e.g., Investigation by the Dep't of Pub. Util. on its own Motion into Modernization of the Elec. Grid,* Docket D.P.U. 12-76-B at 37 (June 12, 2014) ("After careful review of all the information, scientific research, and data presented in this proceeding, and consideration of other jurisdictions' studies, reports and approaches, we conclude that the best balance of these factors is to allow electric distribution companies to include their plans to achieve advanced metering functionality the broad deployment of advanced meters, but to require the companies to provide customers with an option to decline the installation of advanced meters.").

[71] Federal Communications Commission, *RF Safety FAQ,* https://www.fcc.gov/engineering-technology/electromagnetic-compatibility-division/radio-frequency-safety/faq/rf-safety#Q26

protect the public from smart meters."[72] The report further details that even in a worst-case scenario in which a meter is constantly relaying data at a 100% duty cycle, RF emissions "would be measurably below the FCC limits for thermal effects."[73]

Importantly, RF energy is only emitted when smart meters are transmitting data. Research from the Electric Power Research Institute (EPRI) on 47,000 smart meters installed in Southern California found that 99.5% of meters were transmitting for three minutes or less a day. EPRI concluded that smart meters are below FCC limits.[74] A 2010 study from the Utilities Telecom Council provides a useful comparative perspective, highlighting that smart meters present significantly less exposure than many common devices, such as laptop computers (100-200x greater), cell phones (300-100,000x greater), and microwave ovens (50,000x greater).[75]

Consumer Education Non-Profits

The Smart Energy Consumer Collaborative (SECC), an energy consumer education nonprofit, offers an additional view, concluding that "smart meters do not produce any negative health impacts."[76] According to the SECC, even standing continuously in front of a smart meter would result in RF exposure approximately 70 times less than FCC limits.[77]

Court Rulings

In 2015, The Maine Coalition to Stop Smart Meters challenged the Maine Public Utilities Commission's finding that smart meters do not pose a health risk. The case went to the Maine Supreme Judicial Court in 2016, which confirmed the Maine Public Utilities Commission's finding, ruling that smart meters installed by Central Maine Power Co. pose "no credible threat

[72] California Council on Science and Technology, *Health Impacts of Radio Frequency Exposure from Smart Meters* 25, https://www.ccst.us/wp-content/uploads/2011smart-final.pdf.

[73] *Id.* at 15.

[74] *See* Electric Power Research Institute, *Characterization of Radiofrequency Emissions From Two Models of Wireless Smart Maters* v. (December 2011), https://smartenergycc.org/wp-content/uploads/2012/08/000000000001021829.pdf.

[75] *See* Utilities Telecom Council, *No Health Threat from Smart Meters* 6 (2010), https://www.nema.org/Technical/Documents/SmartMeter-NoHealthThreat.pdf (Comparison: cell phone RF frequency when held up to head; microwave RF frequency when turned on and close to door; smart Meter frequency when standing 10 feet away from meter.).

[76] *See* Smart Energy Consumer Collaborative, *Radio Frequency and Smart Meters* (2011), http://smartenergycc.org/wp-content/uploads/2012/01/SGCC-Radio-Frequency-Fact-Sheet.pdf.

[77] *See Id.* at 2.

to the health and safety" of the utility's 615,000 customers who have them installed.[78] The court cited the Maine Center for Disease Control and Prevention's findings in 2010, which concluded there was no indication of "any consistent or convincing evidence to support a concern for health effects related to the use of RF in the range of frequencies and power used by smart meters."[79]

Summary

National Grid understands the public perception of smart meter risk may not be aligned with the available research and evidence from trusted sources. The Company is making it a priority to educate and communicate with consumers and other stakeholders early and often to improve public confidence and acceptance of AMF technology. As explained in Section 7.1.4 and detailed further in the CEP, information on smart meter safety and customer support will be available to customers before, during, and after meter deployment. In addition, the Company will have mechanisms in place to address customer concerns during each phase of deployment. All customers will also have the choice to opt out of the AMF metering program. However, the Company notes that it cannot remove other customers' meters because they are in proximity to the home of a customer who opts out of having an AMF meter.

Additional Resources

The following are additional sources that address AMF health concerns:

- *Evaluating Compliance with FCC Guidelines for Human Exposure to Radiofrequency Electromagnetic Fields*. Federal Communications Commission Office of Engineering & Technology Bulletin 65 (August 1997).
- *Smart Meter – What We Know: Measurement Challenges and Complexities – A Technical Paper to Clarify RF Radiation Emissions and Measurement Methodologies*. Environmental Testing & Technology, Inc. (December 2011).
- *Electromagnetic fields and public health: Base stations and wireless technologies*. World Health Organization (May 2006).
- *Guidelines for Evaluating the Environmental Effects of Radiofrequency Radiation*. Federal Communications Commission (August 1996).
- *Characterization of Radiofrequency Emissions From Two Models of Wireless Smart Maters*. Electric Power Research Institute (2011).

[78] *See Ed Friedman. v. Pub. Util. Comm'n,* ME. Sup. Jud. Ct. at 6 (Jan. 26, 2016), https://www.mainecoalitiontostopsmartmeters.org/wp-content/uploads/2016/01/2016-ME-19-Friedman-Appeal-Decision-1-26-16.pdf.

[79] *Id.* at 8 (citation and quotation marks omitted).

6. Consideration of Alternative Business Models

Realization of full AMF deployment can be achieved in many ways. This section explores various business model approaches to the AMF solution to determine what model is best for Rhode Island and for the Company.

The Company undertook, with the support of its consultant, Accenture, an assessment of alternative business model approaches to the AMF solution it proposed in the 2017 PST Plan. The assessment was completed in the Summer of 2018 to address recommendations included in the November 2017 PST Phase One Report and related feedback the Company received on its AMF proposal in the Docket No. 4780 proceeding. The timing of the assessment also informed the New York AMI business case.

Based on the PST Phase One Report recommendations and testimony from the Division in Docket No. 4770,[80] the assessment included the following areas:

- New and emerging approaches to AMF;
- "As-a-service" offerings;
- "Shared services" opportunities; and
- The relative magnitude of "communication infrastructure backbone" and the impact of potential alternatives.

The scope of the assessment addresses the ASA requirement to evaluate the AMF "ownership model for assets and telecom." In summary, the assessment found that the AMF ownership model the Company proposed in the PST Plan to be an innovative and cost-effective approach to AMF. The assessment recommended that the Company continue down the business model path already developed to implement AMF in Rhode Island. The Company further found that alternatives to its proposed approach were either not cost effective, or represented significant implementation risk due to the market maturity of the option. Additional background, as well as the findings of the assessment are described below.

6.1. Defining Operational Model Terms

Table 6-1 presents AMF vendor service offering options to utilities, ranging from licensed to an end-to-end AMI/AMF as-a-service (AMI/AMFaaS) subscription model. The vendor service offerings are independent of the underlying technology, and whether the utility networks are shared is defined as follows:

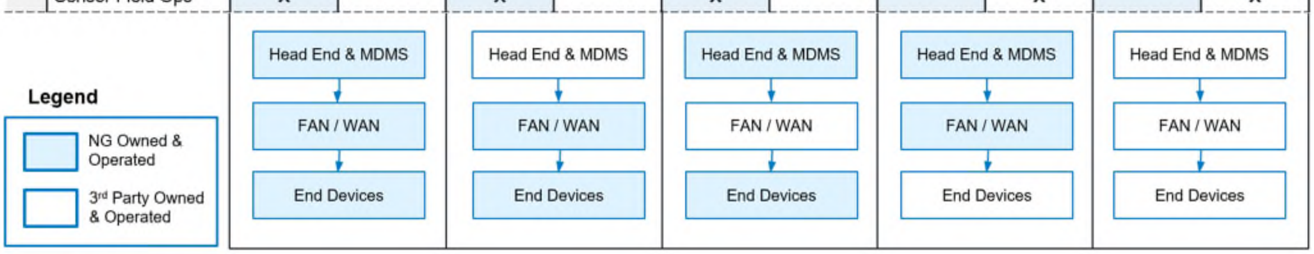
[80] Docket No. 4770, Direct Testimony of Tim Woolf and Melissa Whited at 74-81 (April 6, 2018).

A closed utility AMF network is one in which only the utility's operational devices are used and such devices are only used to transmit the utility's operational data – the architecture is closed to other third-party-owned devices (e.g., water meters, street lights).

A shared utility AMF network is one in which other third-party-owned devices can connect with and transmit data across a utility's AMF network – the architecture is shared between the utility (with the primary function being AMF) and other third-party-owned devices.

Table 6-1: Defining AMI/AMFaaS Offering (Source: Accenture Report)

		Licensed		Software As-a-Service		Network As-a-Service		Meters As-a-Service		AMI As-a-Service	
		Utility	Vendor	Utility	Vendor	Utility	Vendor	Utility	Vendor	Utility	Vendor
Ownership	Meters	X		X		X			X		X
	Modules	X		X		X			X		X
	Sensors	X		X		X			X		X
	Networks	X		X			X	X			X
	Software	X			X	X		X			X
	IT Infrastructure	X			X	X		X			X
Operations	IT Services	X			X	X		X			X
	Back-office Ops	X		X			X	X			X
	Network Field Ops	X		X			X	X			X
	Endpoint Field Ops	X		X		X			X		X
	Sensor Field Ops	X		X		X			X		X



Vendor service offering definitions for the above models:

- **Licensed** software is the traditional approach to utility software procurement which places full financial and operational control of all assets on the utility. Vendor software and IT infrastructure are purchased by the utility and installed on the utility's premise or in the utility's private cloud.

- **Software-as-a-Service (SaaS)** is a vendor managed service offering where the third-party vendor is responsible for the upfront investments of purchasing, setting up, maintaining, managing and monitoring the cloud-based IT infrastructure and software. The third party also provides labor to manage and maintain the systems.

- **Network-as-a-Service (NaaS)** is a vendor managed service offering that provides turnkey FAN/wide-area network (WAN) ownership and operations (back-office and network field operations). Typically, however, vendors that offer NaaS effectively "de-risk" investments into WAN by leveraging their network provider partnership ecosystem to lease backhaul/backbone bandwidth.

- **Meters-as-a-Service (MaaS)** is a vendor managed service offering that provides services around the lifecycle of the meters themselves including finance/ownership, procurement, installation, and field maintenance.

- **AMI/AMFaaS** is a vendor managed service offering that provides a turnkey end-to-end solution which combines SaaS, NaaS, and MaaS to provide a fully integrated solution for clients.

Managed services provided by vendors may include components of one or more of the above, most likely using SaaS as the foundational offering, then adding components of NaaS, then AMI/AMFaaS in that order. On the one hand, "as-a-service" offerings aim to reduce upfront costs and the total cost of ownership while also ensuring that utilities have access to the latest technologies and periodic software upgrades. On the other hand, such models decrease a utility's control over future technology development and represent new commercial contracting risks.

6.2. New and Emerging Approaches to AMF

To identify alternative viable operating approaches, Accenture conducted a market scan for findings of existing and emerging capabilities around the world based on primary research of public information, utility and telecom industry consulting experience, interviews with market participants (e.g., Google Fiber and Leidos) and workshops/discussions with experts from National Grid and Accenture's global network.

The market research consists of approximately 40 alternative ownership examples of utility advanced metering networks (i.e., electric, gas, and water) of entities including investor-owned utilities (IOUs), municipal utilities, co-operative utilities, network and telecom infrastructure providers, metering providers. The market research findings analyzed the ownership and operations of AMF technology solution components considering both shared and closed networks. Key findings from the research are included in the discussion of alternative business models and solution options that follow.

6.3. Exploring "as-a-service" Offerings

Based on the Rhode Island regulatory context, combined with an understanding of market participant offerings and traction from the market research, and subject matter expert input, potential "as-a-service" procurement opportunities were identified and considered by the

Company. Table 6-2 presents a summary of the third-party market participants (left-hand column) and the services they provide across the AMF solution components (top row). The service areas in orange text were identified as the opportunity areas for consideration as part of the Company's AMF solution and implementation plan.

Table 6-2: Services National Grid Could Procure from Third Parties

3rd Party "Sellers" Providing Services to NG

	Meter	FAN	WAN	Back Office IT: Head End & MDMS
Electric	Minimal • Asset ownership • Installation, device & sensor operations, maintenance *Difficult to provide these services between highly regulated entities, moreover, as NG is the only large Electricity & Gas utility in RI.*	Minimal *Given respective network sophistication, its more likely for NG to provide services to a gas/water municipality.*		Minimal • *Unlikely for regulated electric utilities to share software & IT infrastructure ownership or operations* • *NG is the only electric provider in RI*
Gas		Minimal *Gas & Water utilities tend to have less sophisticated IT & communication infrastructure and in-house expertise*		
Water				
Smart City	Minimal	Minimal *Confined to smart city geographic limits with deployed infrastructure (fiber, broadband); limited to the municipality's capacity to provide services (bandwidth availability, technical expertise, etc.)*		Minimal
Metering Contractor	(1) • Installation • Maintenance & replacement	• FAN asset (collector) installation & maintenance	Minimal	
Network Provider	N/A *Would arguably launch a metering business*	Minimal	(2) • WAN ownership & operations • Network mgmt. *NG currently leases WAN bandwidth from incumbent RI network provider*	Minimal
Technology Vendor	• Installation & maintenance – more likely if using vendor proprietary architecture, probably subcontract out to contractor • Asset ownership – unlikely under current regulation	• FAN ownership • Operations & maintenance – likely subcontract to contractor *Particularly with managed mesh-to-cellular*	Minimal *May provide through partnerships with Network Provider*	(3) • Software & IT infrastructure ownership • Software & IT infrastructure operations & maintenance *Utilities are increasingly taking a SaaS approach to back-office IT*
Financier	Minimal – Asset ownership more relevant to smaller muni's and in international markets	Minimal		Minimal

Legend: Considered a viable alternative (dashed green box); Relevant to National Grid's RI regulated utility business (orange); Minimal relevancy to National Grid's RI regulated utility business (grey)

Since the Company is the primary delivery service provider for electric and gas service in Rhode Island, service offerings provided by other regulated or government entities (e.g., gas delivery, water, smart cities) to the Company are not practical. The opposite is more realistic and is discussed in the next section on shared services. The Financier service model, which is seen in international markets, is not considered practical. Under a Financier service option, a specialty financial firm or infrastructure investor provides meter asset ownership and receives "rent" from utilities or energy suppliers. It exists only in specific international markets where the governments and regulators have promoted competitive metering models and developed associated market rules for participation throughout the value chain. For example, in the United Kingdom, energy suppliers are responsible for owning, installing and operating the smart meters and a country-wide independent entity known as the Data Communications Company provides standardized communications platform. There are technological downsides to this approach, which requires plug-and-play metering solutions. For example, the latest AMF technology that includes grid-edge computing and application capability has interoperability limitations that would render a Financier structure more difficult and potentially impractical to implement.

Third-party service providers could potentially provide services to support the Company's AMF solution include metering contractors, network providers, and technology vendors. Consideration of these providers and services within the Company's proposal is described below:

- A metering contractor can provide services such as meter and FAN installation and maintenance. The Company's BCA assumes internal resources install and maintain the meters and FAN equipment. As part of the detailed meter deployment planning phase, the Company may revisit this opportunity to seek efficiencies without increasing costs.

- A network provider, such as Verizon, can provide WAN communications ownership, operations and management. The Company currently leases bandwidth from a network provider and plans to continue with this approach as part of its proposed AMF solution for meter data backhaul.

- A technology vendor could also provide a suite of services, including: meter ownership, installation and maintenance; FAN installation and maintenance; and software hosting and operations. The Company's current proposed AMF solution includes the latter, namely SaaS, for the back-office IT systems, including the HES and MDMS. Considering FAN installation and maintenance services, referred to as NaaS, the Company concluded that with FAN costs representing a relatively small component of total project costs, $11 million nominal (3.2% of total costs) the adoption of alternative telecommunications for the FAN will likely have limited cost impact while significantly increasing implementation risks and future flexibility to further leverage the infrastructure for other business uses.

- With respect to technology vendor meter ownership, the Company does not believe this option is economically viable, particularly for large IOUs with access to capital and low financing costs. In addition, market research also indicates a nascent market for AMF network and infrastructure services defined by small-scale engagements with little indication of business success.

In summary, the Company's current proposal includes "as-a-service" approaches for the WAN and back-office IT systems and may consider meter installation services during the detailed meter deployment planning phase. The SaaS approach for the back-office IT systems is a general trend in the IT space and is increasingly being adopted as part of AMF implementations. The Company believes its proposed AMF solution approach leverages third-party services where they can improve the cost effectiveness and/or capabilities and quality of the solution.

The approach is consistent with the compiled market research that is organized by closed and shared networks in Table 6-3 and Table 6-4. In general, large U.S. utilities own and operate the FAN component of the AMF network and own the meters (i.e., end devices). Increasingly, however, utilities of all sizes have been outsourcing back-office IT services and look to lease backhaul/backbone bandwidth WAN from network providers. As noted, there are different solution approaches in place in international markets that are not applicable in the current Rhode Island regulatory environment. Lastly, due to their relatively smaller scale, less complex network requirements and fundamental differences in business models, municipal and cooperative utilities are increasingly turning to third-party models to reduce upfront costs and total cost of ownership. Not only are these entities looking to vendor "as-a-service" models but they are also engaging larger utilities with existing AMF infrastructure.

Table 6-3: Market Research Inventory of Closed AMF Ownership Models

	Back Office IT (MDMS, Head-end)	WAN	FAN	End Devices	Telecom Model / Architecture	Shared/Closed Network	Own/Operate Network
Lansing Board of Water & Light	Leidos SaaS	Leidos NaaS	Leidos NaaS		Unknown	Closed	Procured aaS
City of Copperas Cove (Water)	FATHOM SaaS (MDMS)				Unknown	Closed	Procured aaS
Newport Utilities	TUNet SaaS				Mesh Network	Closed	Utility
Xcel Energy					Mesh/WiMAX to Fiber	Closed	Utility
Florida Power & Light	Itron SaaS				FAN: Mesh	Closed	Utility
City of Tallahassee					Mesh to Cellular & Ethernet/Fiber	Closed	Utility
American Municipal Power	ElectSolve Saas (MDMS)				Mesh to Cellular	Closed	Utility
Grayson-Collin Electric Coop.		Itron NaaS	Itron NaaS		Cellular-only	Closed	Procured aaS
Puget Sound Energy	L+G SaaS	L+G NaaS	L+G NaaS		Mesh to Cellular	Closed	Procured aaS
EPB Chattanooga					Fiber	Closed	Utility

Note: general direction based on public information and primary market research

Definition of Terms:

- Metering coordinator: responsible for metering services (installation, maintenance, etc.) and contracting with telecom providers for network services
- Meter asset/metering provider: owns the meter (typically a financial entity); also provides installation and maintenance services or contracts to other entity

Legend

- Utility Owned & Operated
- 3rd Party Owned & Operated
- Unknown, information not available

Table 6-4: Market Research Inventory of Shared AMF Ownership Models

	Back Office IT (MDMS, Head-end)	WAN	FAN	End Devices	Telecom Model / Architecture	Shared/Closed Network	Own/Operate Network
UK Utilities	DCC (CGI)	DCC (Telefonica & Arqiva)	DCC (Telefonica & Arqiva)	Meter asset provider	Mesh to Cellular & Long-Range Radio	Shared (Gas & Electric)	3rd Party
Australia Electric Utilities		Telecom providers	Metering coordinator	Metering provider	Mesh to Cellular	Shared	3rd Party
SoCalGas		Verizon / AT&T			Mesh to Cellular	Shared (Gas & Water)	Mixed
Montana-Dakota Utilities	Itron SaaS				Mesh to Cellular	Shared (Elec. & Water)	Utility
New Zealand Electric Utilities		Telecom providers	Metering coordinator	Metering provider	Unknown	Shared	3rd Party
ComEd	Itron SaaS (head-end)				Mesh to Cellular	Shared (Elec. & Water)	Utility
Enel					Fiber	Shared (Telecom Co.'s)	Utility
Kuwait Ministry of Elec. & Water		Zain telecom	Zain telecom		Unknown	Shared	3rd Party
VELCO					Fiber	Shared	Utility

Note: general direction based on public information and primary market research

Definition of Terms:
- Metering coordinator: responsible for metering services (installation, maintenance, etc.) and contracting with telecom providers for network services
- Meter asset/metering provider: owns the meter (typically a financial entity); also provides installation and maintenance services or contracts to other entity

Legend: Utility Owned & Operated (light blue) | 3rd Party Owned & Operated (white) | Unknown, information not available (grey)

6.4. Shared Services Opportunities

This section focuses on U.S. models and approaches as compared to international examples, where governments and regulators have developed vastly different electricity markets in comparison to Rhode Island. In the U.S., there are a limited number of shared AMF/AMI networks between utility entities, with the more prevalent model including a larger IOU that owns its communication network and a smaller utility or municipality (often restricted to gas and/or water) that leases bandwidth. Examples of such shared networks are described below:

- Commonwealth Edison Company (ComEd) announced a pilot with American Water (of Illinois), leasing its existing AMF network. Each entity owns and operates its respective electric/water meters and back-office IT systems but share ComEd's communication infrastructure. American Water had to install vendor-specific communication modules for its water utilities to use ComEd's FAN network.

- Southern California Gas Company (SoCalGas) also shares its AMF network with the Los Angeles Department of Water & Power (LADWP) and the City of Santa Monica's water department. SoCalGas owns and operates its own head-end system (using Aclara technology) while the water entities use an Aclara-hosted and operated head-end (SaaS).

- The City of Bismarck, North Dakota's water department used a public-private partnership to enter a contract with Montana-Dakota Utilities (MDU) to access its AMF communication network. Though MDU manages the entire AMF communications system (FAN/WAN), Bismarck had to upgrade its water metering communication modules to access the shared network.

The Company's AMF proposal includes a commitment to leverage the AMF solution over time to integrate other end-point sensory devices that are both utility and third-party owned to provide additional customer value. As mentioned in Section 5.3.3, such utility devices may include smart gas meters and smart RMD, as well as third-party devices such as water meters and street lights.[81]

The opportunities to leverage the AMF solution for additional Company-owned devices and use cases are less complex compared to integrating third-party devices on a shared network. The complexities of shared network include cybersecurity, data privacy risks, and usage coordination including service-level agreements (SLAs) for availability, reliability, and traffic prioritization on the network. As an indication of the complexity, all but one of the domestic and international shared networks analyzed are shared between regulated entities. In addition, the costs to secure the data and develop robust interoperability requirements could potentially be large and eliminate the benefits of cost sharing or new revenues. Based on these factors, the exploration and evaluation of network sharing opportunities is a significant undertaking that requires a careful and comprehensive effort between the Company and third parties. The Company will continue to monitor developments in other jurisdictions to leverage industry learning for potential shared-network opportunities.

6.5. Telecommunications Infrastructure Alternatives

The alternative business model assessment also considered the broad concept of a statewide shared network (SWSN) from its impact on the Company's approach to AMF technology architecture, the various players, and performance requirements of Rhode Island participants. The assessment considered several key recommendations from the PST Phase One Report including:

- Consider leveraging existing infrastructure for next-generation networks;
- Explore synergies in connectivity needs between the Company and the public-infrastructure sectors;
- Understand potential impacts to Rhode Island of different approaches to a SWSN; and
- Consider cost savings opportunities to AMF through network partnerships.

[81] Section 5.3.3 includes additional detail about these opportunities.

With respect to the AMF plan that includes a private mesh FAN and public cellular WAN, three alternative SWSN telecommunication technologies were compared, including end-to-end cellular, mesh-to-fiber, and fiber-to-x (meter or home). The alternatives are depicted in Figure 6-1, along with a summary of the quantitative and qualitative findings of the assessment.

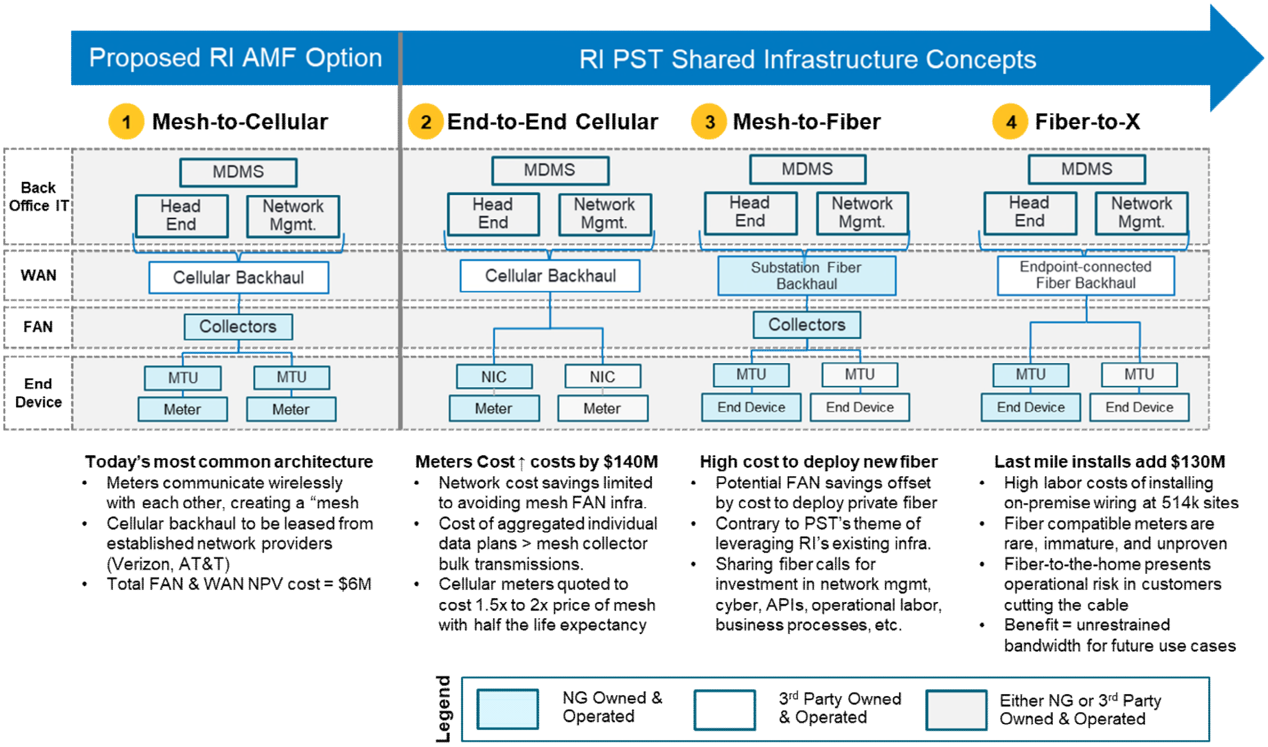


Figure 6-1: SWSN Technical Options Cost Comparison

Mesh-to-Cellular (Utility-Owned FAN, Third Party-Owned WAN): This is the most common AMF architecture, particularly for large IOUs, and is proposed as the Company's AMF strategy. In this model, meters communicate wirelessly with each other, creating a "mesh" that connects to field-deployed (pole-mounted) collectors that transmit bulk meter data to the utility's back-office over a cellular backhaul. Under the Company's proposed architecture, cellular backhaul would be leased from established network providers such as Verizon and AT&T. However, the Company may consider moving towards a Company-owned private network for backhaul as a part of future operational telecommunications processes. Despite estimated FAN and WAN costs of $21.6 million nominal (6.3% of total costs), there are potential savings from the following:

- **WAN Avoidance**: The cost of leasing backhaul/backbone bandwidth from an SWSN compared to the cost of leasing from the current network providers Verizon and AT&T.

- **FAN Avoidance:** The cost of enabling direct connections to SWSN infrastructure and thus eliminating the need for FAN collectors.

The findings of the assessment conclude that while very modest savings may be possible in telecommunication costs by using the SWSN, the enabling AMF metering and operations solution costs would increase significantly. As such, the SWSN alternatives analyzed are expected to lead to overall negative impacts on the Company's total cost of the AMF solution.

End-to-End Cellular (Third Party-Owned FAN & WAN): Under the current Rhode Island AMF strategy, National Grid is planning to use cellular technology as a cost-effective alternative for 5% of the 525,000 two-way communicating meters (e.g., meters located in remote areas), to limit the need to build out additional mesh infrastructure. However, when evaluating the option of leasing cellular backhaul/backbone bandwidth from a SWSN, potential network-related cost savings are limited to avoiding the mesh FAN infrastructure. Such potential savings are outweighed by the added costs of cellular meters, as well as the increased costs of individual end-point data plans compared to bulk data transmission in a mesh-to-cellular approach. These findings are supported by the following data:

- Cellular meters are quoted to cost 1.5 to 2 times the price of the mesh alternative and have half the life expectancy (i.e., 10 years). The relative costs were developed as part of the RFS process.

- The aggregate cost of individual data plans for each of the 525,000 meters is expected to be significantly higher than bulk data plans of collectors in a mesh-to-cellular architecture.

Mesh-to-Fiber (Utility-Owned FAN & WAN): The third approach would leverage the Company's established transmission and sub-transmission fiber network as part of the backhaul/backbone to a mesh-to-fiber strategy. Given that fiber is currently deployed at approximately 6% of substations, the Company would be required to further invest in developing its private fiber network to connect all mesh collectors.

- Any potential savings to FAN infrastructure in using mesh-to-fiber collectors is offset by the additional costs to deploy private fiber.

- The Company believes this approach is contrary to the PST's underlying theme of leveraging the State's existing infrastructure.

- Before National Grid can lease bandwidth as a participant in a SWSN, considerable investment in network management, cybersecurity, supporting infrastructure, application programming interfaces (APIs), operational labor, business processes, etc. would be required to its application-built private fiber network.

Fiber-to-X: (Third Party-Owned WAN): Even though Rhode Island already has substantial fiber-to-home infrastructure deployed to 84.9% of residents,[82] considerable last-mile investment would still be required if National Grid were to consider an end-to-end fiber approach to AMF regardless if it were a private or shared network. In addition to the labor costs of installing on-premise wiring at 525,000 sites, the following are other factors to consider:

- Fiber compatible meters are extremely rare, immature, and unproven in today's market.

- Assuming that fiber termination points are conveniently located near meter sockets, additional infrastructure and installation labor would be required above and beyond the basic meter swap.

- Physical fiber-to-the-home connections present an operational risk in that customers cut the cable resulting in additional reconnection costs. Similar to the above approach, leasing bandwidth as part of a SWSN will require considerable investment in network management, cybersecurity, supporting infrastructure, APIs, operational labor, business processes, etc.

- A benefit to such an approach would be practically unrestrained bandwidth for any evolving or future use cases that generate larger data sets (although this is not currently forecast or cautioned by meter vendors).

While the opportunity to partner with network providers, municipalities, cooperatives, and non-profits to create a SWSN exist, the potential technology solutions are not a cost-effective option for the AMF solution. In addition, major challenges exist with respect to the formation of a SWSN, including high costs, lack of technological advancements, and regulatory enablement. As these factors evolve in the future, so can the Company's consideration of its role in a SWSN.

[82] *See* https://broadbandnow.com/fiber.

7. Program Implementation

This section outlines the various components of AMF implementation, including the implementation timeline, meter deployment, customer engagement, program management, the impact on existing customer programs (e.g., EE), and opportunities for multi-jurisdictional synergies.

7.1. Timeline

As shown in Figure 7-1, the Company proposes a three-and-one-half year AMF deployment program. Phase one, which covers the first two years following regulatory approval and a managed project ramp up, will address detailed design, remaining procurement activities and the installation and upgrade of the back-office systems. Phase two, beginning in the last quarter of phase one and running for approximately one year, focuses on deploying the communication network. Phase three, which would commence after the completion of phase one, involves deployment of electric meters over 18-months. During the phase three electric meter installation, the Company will also begin installing AMF gas modules as part of its business-as-usual (BAU) activities in AMF-enabled areas. In addition, the Company will engage customers, as set forth in the CEP, with activities occurring before, during, and after meter deployment. The Company has also provided an illustrative view of the anticipated timeline for development, approval, and implementation of TVR, which would occur as part of a separate docket.

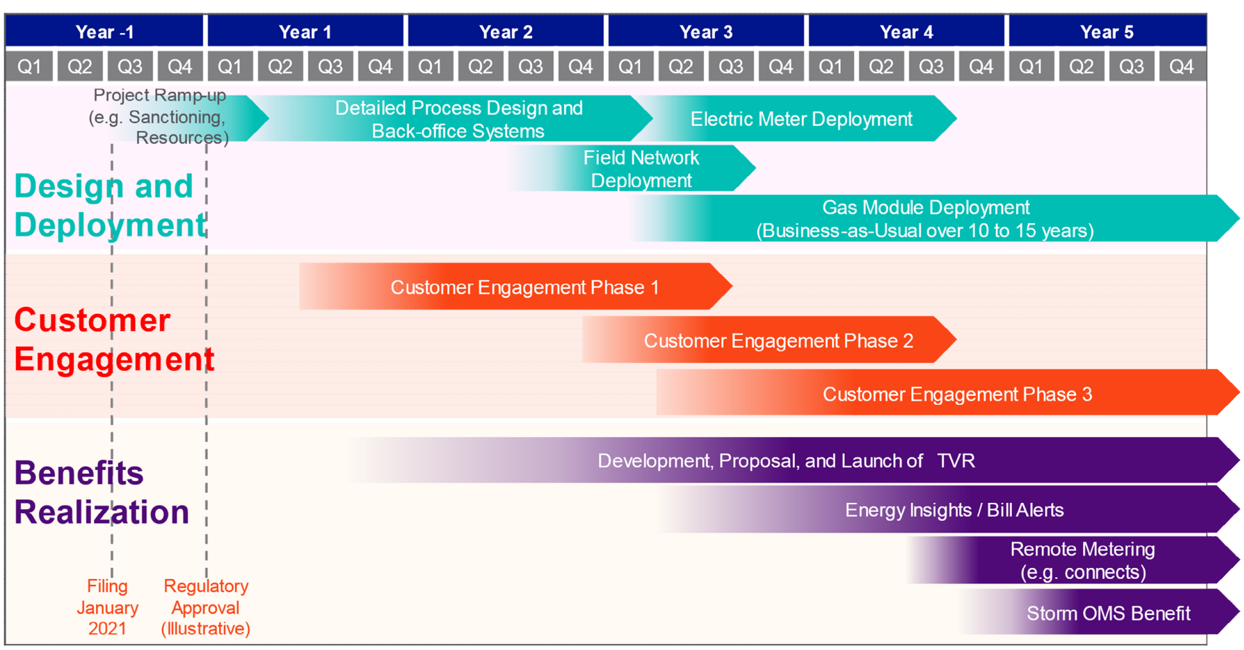


Figure 7-1: Illustrative AMF deployment timeline

7.1.1. Back-office Implementation and Process Design

The first stage of deployment – the installation and upgrade of the back-office systems and process design work – will begin after AMF program approval and the ramp-up period.[83] During this time, the Company will conduct detailed design work, holding cross-functional workshops to identify key priorities, as well as developing and refining an integrated meter and FAN deployment strategy. The design strategy will seek to maximize benefit realization for customers while mitigating any potential equity issues that are identified. With New York approving AMI for the Company's affiliate in advance of Rhode Island, the ramp-up and phase one activities could be shortened. For further detail, Figure 7-2 illustrates activities the Company will perform at each stage of deployment.

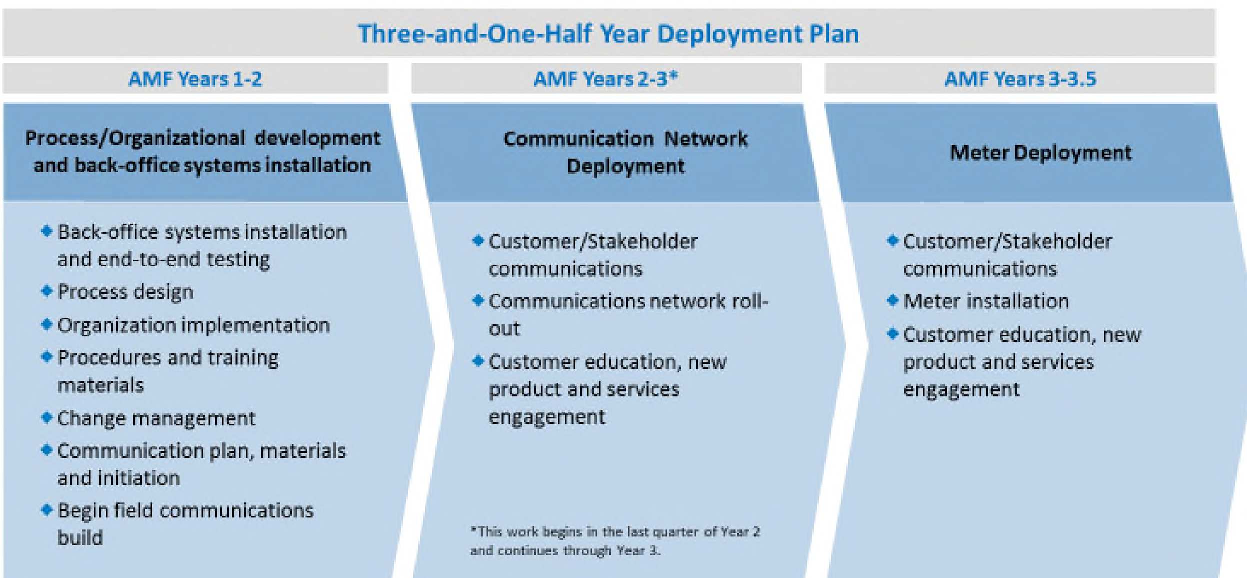


Figure 7-2: Implementation Phase and Activities

*Note that AMF-enabled gas modules will be deployed BAU

7.1.2. Communication Network Deployment

The Company will initiate the communication network deployment work at the tail end of the back-office implementation and process design work. The communication network deployment will overlap with the last quarter of the two years of back-office work and continue through meter deployment. The communication network deployment will execute on the FAN strategy developed during the back-office implementation and process design. As outlined in the CEP,

[83] The managed ramp-up period will allow for project sanctioning, contract execution, and onboarding resources.

the Company will also seek to begin communicating with customers and stakeholders during this time to provide information on expected deployment timelines, what customers can expect during meter deployment, and the benefits enabled by smart meter deployment.

7.1.3. Meter Deployment

During meter deployment, the Company proposes to install approximately 525,000 electric AMF meters across its service territory. The Company will design the AMF meter deployment in concert with the planned replacement cycle of the AMR electric meters, to best manage deployment costs and mitigate remaining net book costs.[84] As shown in Table 7-1, the Company will install approximately 67% of the electric AMF meters in the first year of meter deployment, followed by 33% in year two. The Company anticipates the electric meter deployment to vary locally across the state based on considerations such as geographic area, population density, and dual-fuel customer saturation. During this time, the Company will also ensure coordination among the different deployment components: meter delivery, equipment staging, resource planning, remaining FAN deployment, and ongoing customer engagement.

Table 7-1: National Grid's meter implementation schedule

AMF Year	Electric Meters Installed	Gas Modules Installed
3	67%	7.85%
4	33%*	7.85%
5		7.85%
6		7.85%
7		7.85%
8		7.85%
9		7.85%
10		7.85%
11		7.85%
12		7.85%

*Electric meter installation is expected to be completed halfway through the second year of meter installation.

[84] While the Company is seeking to mitigate unrecovered AMR costs, it continues to install and replace a subset of AMR meters in response to customer growth, meter testing requirements, and meter failures. The Company will seek to amortize the unrecovered investment over a specified period to be determined in its next depreciation study and rate case.

The Company plans to install AMF-enabled gas modules as a part of the routine replacement cycle; anticipating it will take approximately 10 to 15 years to replace all gas modules (note: the table above only shows ten years of module replacement). AMF gas module installation, like AMF electric meter installation, would begin in year three of the AMF program, and continue in accordance with the gas module asset lifecycle schedule. Actual percentages of gas modules installed may vary year-to-year when compared to Table 7-1 due to access constraints at the customer premises.

As is discussed in Section 5.3.3, gas meter technology is advancing to include sensing and control enhancements that would increase customer safety. As this "smart" gas technology becomes available, the Company will evaluate whether it makes sense to deploy it on an accelerated basis, which would supersede the module replacement schedule Table 7-1.

7.1.4. AMF Meter Opt-out

The Company is committed to customer choice. To that end, it has incorporated two different customer decision points into its AMF proposal: 1) the ability to opt-out of receiving an AMF meter; and 2) the opportunity to receive an AMF meter, but not participate in TVR. This section addresses the meter opt-out process.[85] During all phases of deployment, customers will have the opportunity to decline the receipt of a new smart meter. Customers will receive advanced notice of plans to install AMF meters via mail and other outreach methods, such as radio and educational events. The outreach will notify customers of their ability to opt out, as well as the procedure required to do so. Customers wishing not to participate in the AMF metering program will be able to opt out before or after receiving the new meter.[86]

Processes and resources will be in place to support customers who are considering or have decided not to participate in the program. Electric customers who opt out will receive a non-AMF meter. Likewise, gas customers who opt out will not have the gas module installed. The Company will manually read their meters monthly, and, similar to those who opt out of receiving an AMR meter today,[87] they will be subject to a one-time meter exchange fee in addition to a monthly manual meter reading fee.

If a customer chooses to opt out of a meter, the Company will seek to understand the reason for the customer's decision not to participate in the AMF program. This will allow the Company to focus additional resources toward other sectors, or specific customer groups that may consider opting out for similar reasons. In addition, customers who opt out of a smart meter will receive

[85] The separate and distinct optionality regarding TVR is used on an illustrative basis to calculate the BCA, and it is discussed further in Section 8.2.1.

[86] During demonstration project meter installation for the Company's New York affiliate in Clifton Park, most customers who opted out of receiving a meter did so through the call center or in person at the time of installation.

[87] *See* Docket No. 4342 in which the PUC approved the current AMR opt-out fees.

additional materials on the smart meter benefits they are likely to forego by not participating, including access to features and services that require smart meter data (e.g., more personalized usage insights and bill-saving opportunities with new TVR plans).

For the purposes of the BCA, the Company assumes that 1% of customers will opt out of AMF meters. The assumption matches the highest value of the AMI meter opt-out range identified by Consolidated Edison Company of New York, Inc. (Consolidated Edison) in a survey of peer utilities.[88] By comparison, the Company's New York affiliate experienced a 0.2% opt-out rate for the installation of electric AMR meters (approx. 3,200 out of 1.7 million) on a territory-wide basis, and a 0.4% opt-out rate for gas AMR (approx. 2,500 out of 640,000). The two AMF pilot programs, Worcester and Clifton Park, experienced slightly higher opt-out rates of 5% and 8%, respectively. Notably, the pilots differed from the proposal here in that they did not include meter reading and replacement charges for opting out, and, in the case of the Clifton Park Demonstration, it did not include a TVR component. The Company, therefore expects opt-out rates in line with its prior experience and that of Consolidated Edison's benchmarking report. Moreover, the Company's proposal includes a robust CEP with significant effort dedicated to education and outreach, which the Company believes further supports its assumed 1% opt-out rate. Additional detail on customer choice is included in the CEP (Attachment A) and Section 8.4.1.

7.2. Customer Engagement

Customer engagement is one of the most important pieces of the proposed AMF program. National Grid is focused on delivering a simplified and enhanced customer experience, making the benefits enabled by smart meters intuitive and the functionality easy to manage. The CEP (Attachment A) presents the Company's plan for educating, engaging, and empowering customers to maximize these benefits.

Many of the benefits lie within the increased granularity and timeliness of the energy usage data the AMF system will deliver. Access to this information helps tie energy usage directly to the cost of energy, incentivizing changes through bill savings and by driving step changes in peak energy reduction, especially when combined with future TVR designs. Customers will benefit from:

[88] *Proceeding on Motion of the Comm'n as to the Rates, Charges, Rules and Regul. of Consol. Edison Co. of New York, Inc. for Elec. Serv., Advanced Metering Infrastructure Business Plan*, NYPSC Case No. 15-E-0050 at 38 (November 16, 2015) ("Customer acceptance of AMI is high as evidenced by very low meter 'opt out' and resistance rates coupled with increasing customer recognition of benefits in controlling their use and costs. Average opt-out rates for peer utilities were less than 1% with reported data ranging from .0003% to 1%."); *see also* Consolidated Edison Co., *Advanced Metering Infrastructure Benchmarking Report*, 5, 39 (October 15, 2015).

- Improved access to timely energy usage data;
- Enhanced control over energy management and costs; and
- Better connections to third-party vendors for innovative energy solutions.

Maximizing customer engagement requires a deeper understanding of who the Company's customers are, what they need, and what they want, as well as a recognition that those needs and desires are not uniform across all customers.

7.2.1. Customer Strategy and Segmentation Insights

To better serve Rhode Islanders, the Company completed a needs-based customer segmentation of its residential and commercial customers. Through this process, the Company identified six residential and five commercial segments, each of which contains in-depth profiles of energy-related attitudes, products and services customers are interested in, engagement preferences and favored means of interaction. With each of the Company's residential and most of its commercial accounts now coded with their respective segment, the Company is well positioned to engage customers on the benefits of AMF in a more personalized way through preferred messages and communication channels.

National Grid has begun to leverage these insights to better identify and target customers for different product and service offerings. For example, the Company's residential analysis revealed two segments ("Educated Eco-Friends" and "Affluent Conservers") that are most interested in engaging with National Grid by purchasing energy-related products and services; about 30% to 35% of Rhode Island customers fall into these groupings.

Notably, many of the products and services classified as low awareness but high interest across customer segments are relevant to AMF-enabled functionality, such as TVR, bill alerts, access to more granular energy usage data, and load disaggregation.

For the CEP, which seeks to engage *all* Rhode Island customers, the Company expects to utilize digital footprint habits (i.e., how customers use technology) and desired brand interaction channels (e.g., website, phone calls, paper bills, and apps) from each segment to differentiate its outreach to customers with preferred messages and communication channels (e.g., direct mail, website, email, social media, community meetings, and the RI Energy Innovation Hub). This approach will help the Company most effectively educate and empower different customers to maximize the benefits of AMF. Personalized messaging through preferred channels improves the customer experience and will prompt customers to engage more actively with AMF by utilizing newly available granular energy data to manage energy costs, connect with third parties, and potentially engage with future technologies, like load disaggregation and smart home device integration.

The Company will continue to test and learn from its segmentation analysis to optimize between universal and targeted messaging. The Company will also refresh its segmentation analysis periodically to ensure its insights remain relevant and useful to ongoing customer engagement efforts. Additional details on the Company's customer strategy and segmentation insights and how they impact the Company's plan to engage customers as part of AMF deployment are included in the CEP (Attachment A).

7.2.2. Phases of Customer Engagement

The objective of the CEP is to inform and educate National Grid customers on the benefits of smart meters, to increase participation in adopting the new technology, and to empower them to utilize new insights and services. Using the learnings from its AMF pilots, customer strategy and needs-based segmentation analysis, as well as internal and external research and collaborative sessions, the Company developed a three-phased approach to customer education and engagement. A summary of the three-phased approach is shown in Figure 7-3 and described in detail in the CEP.

- **Phase One (Awareness):** Prior to deployment, the Company will build an extensive collection of informational materials and marketing collateral to support customer communication and engagement activities, educate and train internal resources, and begin a territory-wide customer and stakeholder outreach effort to build smart meter awareness, generate interest prior to meter installation, and address customer concerns.

- **Phase Two (Deployment):** The Company plans to build on phase one and narrow the focus of communication toward individual customers in the months leading up to and during smart meter installation, as outlined in its 90-60-30-day communications plan. The Company will engage customers with tactical information that will guide them through the day of meter installation, including the timeline of events, what to expect, and alternate choices available including opting out of meter installation. The Company will also utilize its customer segmentation insights and customer behavior learnings from its AMF pilots to maximize engagement with different customer types.

- **Phase Three (Empowerment and Enablement):** After smart meters are installed, the Company will shift its focus to empowering and enabling customers to take full advantage of their more granular, timely energy usage data. The Company continues to build out its CEMP, which will be customers' new touchpoint to access their energy data in CEP phase three. The sustaining nature of this phase will focus on helping customers understand how to use this platform, including how to interpret their energy consumption and how to manage their energy usage to reduce energy and costs to effectuate bill savings. In this phase, the Company will also help to further facilitate the introduction of interested customers to third-party vendors capable of supplementing customer needs with new and innovative products and services.

The Company will also leverage the more granular usage data to develop new targeted and innovative EE programs that will allow for continuous customer engagement and more personalized energy usage alerts and recommendations as detailed in Section 7.5.

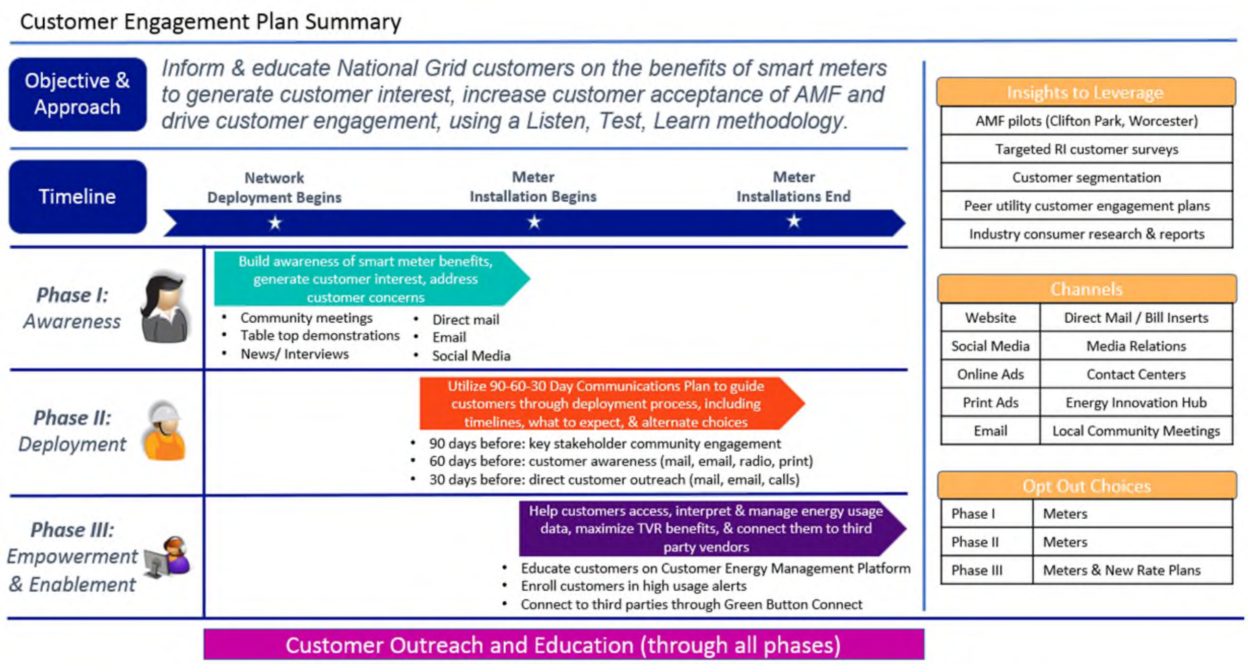


Figure 7-3: Customer Engagement Plan Summary

Throughout the three phases, the Company will continue to collect customer feedback through additional online surveys, mail surveys, telephone surveys, in-person focus groups, online focus groups, and customer forums as part of its overarching "Listen, Test, Learn" approach to smart meter deployment.[89] It will use these channels to track key metrics on customer awareness of AMF features and benefits, customer satisfaction with meter deployment and billing accuracy, opt-out rates, and customer enablement and empowerment through use of and satisfaction CEMP functionalities.

[89] Listen, Test, Learn was developed by National Grid as an approach to customer education and feedback that aided in early program design and ongoing adaptation of the Worcester Pilot. For example, the Company conducted a public summit during the design phase that allowed it to hear from a diverse cross-section of the community and incorporate ideas from customers to improve design of the project. *See* Association of Energy Services Professionals, *Listen, Test, Learn – National Grid's Smart Grid Pilot* (June 2016), https://aesp.org/page/ListenTestLearn/Listen-Test-Learn---National-Grid-Smart-Grid-Pilot.htm.

7.2.3. AMF & National Grid's Long-term Customer Vision

The deployment of the smart meters and associated communication network will provide significantly more granular data at a greater frequency than is available with current AMR technology (15-minute vs. monthly intervals, respectively). National Grid is committed to enhanced third-party data access, which will create new opportunities for innovative third-party services. AMF will establish a two-way communication pathway between National Grid and the customer, and establish a grid-edge computing platform, including software applications that are deployable to the meters for both grid- and customer-facing use cases. Once AMF is deployed, National Grid will seek to leverage this foundational infrastructure and capabilities to provide new customer solutions where feasible.

7.2.4. Data Governance and Management

The Company's Data Governance Plan (Attachment B) lays out a comprehensive set of principles and standards for the customer and system data produced by the Company's proposed AMF deployment. These guiding principles are designed to ensure that the data generated is collected, managed, stored, transferred, and protected in a way that preserves customer privacy, is consistent with cybersecurity requirements, and facilitates data access in furtherance of operational requirements, as well as grid modernization and clean energy objectives. The Data Governance Plan provides a structure for how AMF data will be governed. The plan also discusses system data as it pertains to AMF in the context of ongoing grid modernization efforts.

With feedback provided by the PST Advisory Group and the Subcommittee, the plan includes an explanation of how the Company will provide customers with access to data, and how it will enable the sharing of that data with NPPs and other authorized third parties. In addition, the Company proposes a new data use case evaluation process, where ideas can be submitted and discussed collaboratively with the PST Advisory Group with a focus on delivering maximum value for customers.

The Company has developed a comprehensive and integrated data governance framework designed to ensure compliance with privacy and information security regulations across all jurisdictions in which it does business. The framework is meant to ensure that customers' data is properly protected, but also readily available to them or any third party with whom they wish to share their data. In striking this balance and committing to the secure delivery of AMF, the Company focuses on three key data security components: 1) a commitment to core data-privacy principles; 2) regular assessments of the Company's performance in accordance with the principles; and 3) constant vigilance. The approach is also reflected in its risk-based cybersecurity framework that tracks across people, process, and technology:

- Setting forth policies and standards intended to ensure the Company works to common security objectives by regularly updating privacy and security guidance (including incident management and reporting) for those with legitimate business needs to access customer data;
- Addressing privacy throughout the data lifecycle, working to prevent accidental misuse/loss/exposure of information; and
- Ensuring cybersecurity controls are implemented, information risks are understood, and technologies are selected to keep pace with threats.

The Data Governance Plan, included as Attachment B, provides further detail of the Company's approach to data, privacy, and its commitment to cybersecurity, including discussions of:

- Customer Energy Data;
- System Data;
- Data Access;
- Data Sharing;
- Green Button Connect;
- Home-Area Networks;
- Data Use Case Evaluation; and
- Data Privacy, Security, and Protection.

7.3. Program Management

The Company establish a project management office (PMO) directly linked to workstreams, serving as the conduit between the project front line and other business units. The PMO will be supported by the Transformation Office, which was created to enhance the Company's commitment to being at the heart of clean, fair and affordable energy future for customers. The Transformation Office, along with Gas Transformation and Electric Transformation business units will help the PMO deliver new and exceptional customer value by aligning the Company's strategic planning, portfolio management, process excellence, and change management capabilities. Through this approach, the Company is well positioned to efficiently deliver major projects like AMF in a cohesive manner that provides benefits for customers and addresses the Company's operational needs.

In addition, the AMF project will leverage a robust set of National Grid standards developed as part of its Business Management System (BMS). Specifically, a set of BMS standards has been developed around program and change management. As set forth in Figure 7-4, the standards include ten core principles that the AMF project will adhere to for promoting common practices and successful outcomes. Each principle has been well defined and includes a related set of performance requirements. Furthermore, the BMS standards are accompanied by a comprehensive Company portal that includes training, tools, and templates. An illustration of the core principles for program and change management appears below.

Figure 7-4: Core principles of program and change management standards

The Company is also leveraging its Centers of Excellence (COEs), which will lend internal support to the AMF project team. The COEs will provide experienced services in several important project areas, such as program management, change management, business architecture, and process mapping. Additionally, the COEs provide for an independent assessment of the AMF project through their program assurance and project controls teams.

While the proposed AMF deployment timeline includes two years for back-office systems implementation and detailed design, the Company recognizes the importance of proactive planning to ensure internal resources are appropriated and organized to successfully deliver AMF. The Company is also taking steps to prepare Requests for Proposals (RFPs) for external support in the areas of project management, business integration, and IT integration (discussed further below). Such “implementation readiness” activities also include assembling project plans and schedules, organizational resourcing, establishing business unit collaboration and communication processes, and preparing for internal sanctioning processes. This work is ongoing in support of the New York affiliate’s AMI program and will continue in advance of the Rhode Island AMF proposal.

7.3.1. Governance

The Company will establish an AMF program governance structure, which will include representation from senior leadership and subject matter experts from across the Company. An illustrative example of the governance structure is included as Figure 7-5. In doing this, Company will build from the work being done to support the deployment of AMI by its upstate New York affiliate and incorporate lessons learned from discussions with other large internal programs, as well as meetings with consultants and peer utilities who have implemented AMF.

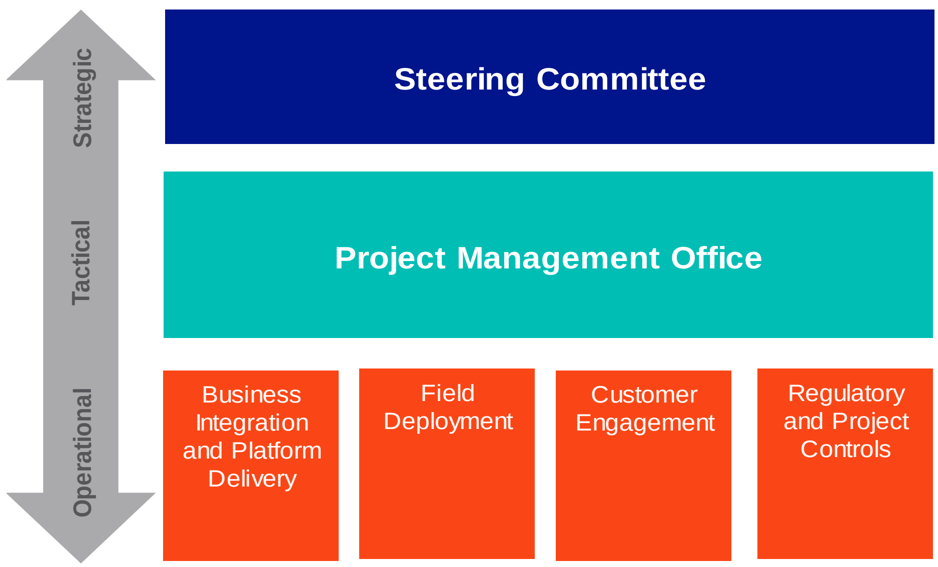


Figure 7-5: Example program governance structure

7.3.2. Company Staffing and Training

The Company expects to utilize a mix of new and existing employees to manage AMF program implementation in Rhode Island. In some cases, as AMF changes the way the Company operates, existing employees will be repurposed to fill new positions. Additional staff is expected to support areas such as project management, implementation, change management, and business integration.

As discussed in more detail in the CEP, the Company will provide AMF training to all Company employees with an emphasis on customer service representatives, who will serve as a primary conduit for customers interacting with the new technology and services. Training will be provided through a variety of channels and materials to ensure that information is delivered and accessible to all employees. The channels and materials include:

- Company Town Halls;
- Employee Communications;
- Emails;
- In-person Training Sessions;
- Frequently Asked Questions (“FAQ”) Resources;
- User Manuals; and
- Instructional Videos.

As implementation of AMF progresses, the Company intends to utilize existing employees’ capabilities to analyze and leverage AMF data to maximize energy saving benefits and assess the overall impact of AMF implementation. Teams within the Company, such as Advanced Analytics and Energy Forecasting, have skills in both electric domain knowledge and quantitative analysis to ensure the Company is capturing and delivering benefits. Additional capabilities include:

- Quantitative analysis associated with short-, mid-, and long-term electric and gas system distribution planning;
- Predictive and prescriptive analytics;
- Modeling DERs such as solar, EV, and energy storage and their impact on the Company’s network; and
- Forecasting customer demand, accounting for weather variability, price elasticity, economic growth rates, technology trends and other variable factors.

Examples of advanced analysis that would be possible with AMF data include improved load modeling, customer energy saving strategy design, preventative maintenance, and theft detection.

7.3.3. Customer Integration

The Company will also use the CEP to inform and educate customers about the benefits of smart meters. The outreach efforts are aimed at increasing participation and acceptance of the new technology, as well as the eventual adoption of new insights and services.[90] To implement the CEP, the Company will coordinate with internal teams focused on customer engagement, such as Customer Insights, Marketing, Customer Energy Management, and Customer Experience Products. Working collaboratively, this internal coordination will ensure the materials, processes, and outreach efforts defined in the CEP are successfully executed. As customer needs evolve, the team will develop the means through which insights or benefits continue to be delivered to customers.

[90] *See* Section 7.2 for additional information about the Company’s three-phased approach to customer engagement.

7.3.4. Business Integration

Business integration is an important step toward ensuring AMF implementation is successful and efficient. It strengthens the Company's AMF-related communication and collaboration processes across the business units, ensuring the project's resources are holistically aligned. Additionally, by proactively managing change, business integration provides for a smooth transition into the ongoing management of the AMF resources and associated programs once the initial deployment is complete.

Many employees will be impacted by the AMF deployment, including meter field technicians, meter shop technicians, customer service representatives, control center operators and billing analysts. Each role will be changed to some degree to accommodate the incorporation of this new technology. To aid in a smooth transition, the business integrator will promote internal communication, engagement, and adoption of the AMF technology and functionality across the Company. This will include alignment with programs such as the deployment of a Customer Information System (CIS), grid modernization investments, as well as other IT business objectives.

The business integrator will also be supported by industry-leading consultants and will establish robust partnerships with other teams across the Company. The objective of establishing these partnerships is to raise awareness of the AMF efforts, coordinate tasks to ensure efficient implementation, and build change management processes to enable the transition to new ways of working once AMF program implementation is complete.

7.3.5. Systems and Grid Integration

Likewise, systems and grid integration activities are key to harnessing the full capability of smart meter benefits across the Company's infrastructure, software, and systems. By successfully deploying physical equipment and enabling data exchanges between the meters, modules, and collectors to back-office systems, the Company can maximize the effectiveness of the overall AMF platform. As such, various costs associated with IT and systems integration are included in this Updated AMF Business Case. The Company's approach to systems and grid integration includes:

- Capability analysis and end-to-end definition of functionality at each step;
- Systems architecture to define data interfaces between systems and components;
- Defining detailed requirements for all systems and interfaces;
- Custom configuration and development of system APIs;
- A well-coordinated deployment strategy that minimizes the impact to communities and customers;

- Detailed test case planning and definition; and
- Careful test execution and defect documentation.

In general, AMF platforms have highly complex data exchanges. To address these complexities and facilitate the exchange of standardized data elements between all affected systems, the industry has turned to systems integration solutions supported by an enabling middleware technology, such as an enterprise service bus (ESB). The Company plans to follow this same industry-accepted approach. In addition to a functional platform, other benefits of strong systems integration include:

- Improved system response time and performance;
- Lower labor costs and increased operational efficiency; and
- Compatibility across system devices and software.

The Company's systems- and grid-integration teams will manage these activities in coordination with a dedicated IT PMO team and qualified vendor partners, who will be chosen through the vendor selection and management process.

The Company has also been evaluating future-state customer system technology to eventually replace existing legacy systems used for billing across its jurisdictions with a single, more flexible and adaptive platform. The Company's analysis shows that the legacy system used now to support Rhode Island customers will be stable for integration of the MDMS employed by AMF. Given this, the Company has determined that moving the legacy system in Rhode Island to a new platform *after* AMF deployment mitigates potential risk from simultaneously deploying two large programs. This sequencing of projects allows the Company to focus on each large-scale deployment individually while still delivering benefits to customers efficiently.

7.3.6. Vendor Selection and Management

The Company conducted its procurement and vendor negotiation activities taking into consideration requirements for all jurisdictions/regions within the National Grid footprint through a competitive RFP/RFS process. This approach enabled National Grid to obtain optimal pricing and value for customers. The Company managed the AMF vendor selection process within a defined governance framework, considering a range of factors, including current and future technical capabilities, fixed delivery costs, industry experience, risk mitigation and reporting protocols. Additionally, the Company considered vendor experience with AMF system deployments, as well as large-scale manufacturing capability.

The Company's vendor selection process also included a Request for Information (RFI) to qualify potential bidders based on their ability to support the defined business requirements. Vendors deemed qualified through the RFI process were permitted to submit responses to the RFS. Once the responses were received, the Company engaged each vendor to clarify outstanding questions or uncertainties regarding the proposed solution, capabilities and pricing. In addition, the Company conducted vendor site visits to assess vendor research and development and manufacturing facilities, where applicable. To gain additional insight into vendor capabilities, the Company also collaborated with peer utilities who have installed similar software and equipment. After final contract execution, and onboarding, the Company's program team will coordinate with the vendor to deliver the project in line with defined schedules and SLAs.

The Company anticipates Rhode Island will be the second National Grid jurisdiction to implement AMF technology with the selected vendor. As such, Rhode Islanders will benefit from the ongoing RFS activity occurring in New York, including the potential for lower costs due to volumetric pricing discounts and multi-jurisdictional efficiencies. Should the Company determine that additional RFP / RFS events are required, Rhode Island requirements will be taken into consideration and the Company will follow the process described above.

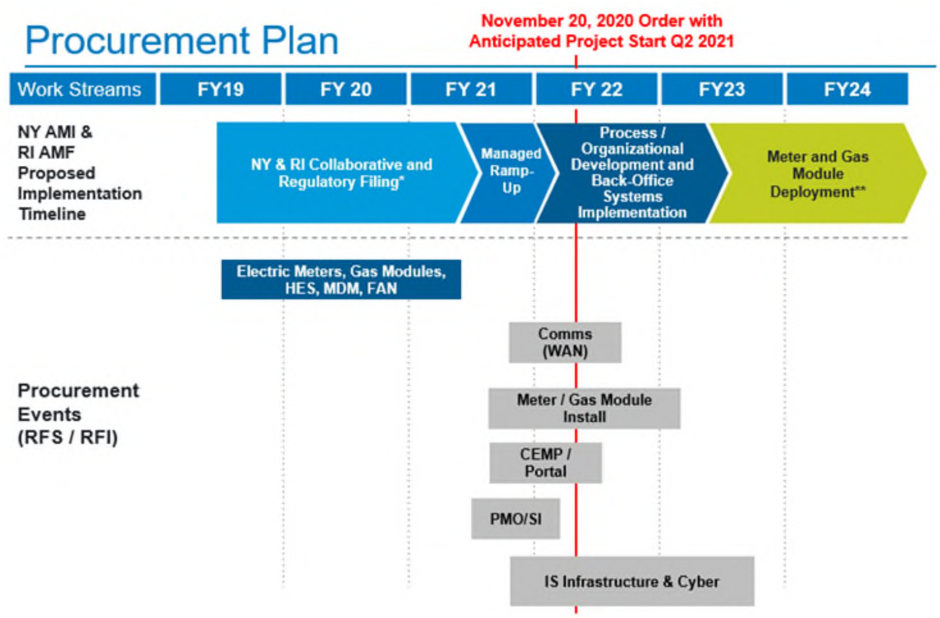


Figure 7-6: Procurement timeline

* The Company's New York affiliate filed its AMI Implementation Plan Report on November 15, 2018 and made a supplemental filing September 4, 2019. The NYPSC approved NMPC's AMI proposal on November 20, 2020. This figure provides an illustrative view of procurement in New York.

** The NY proposal includes two years of back-office system installation followed by a four-year window for meter and gas module deployment.

As shown in Figure 7-6, the Company's New York affiliate had progressed a considerable amount of procurement work for the RFS components in anticipation of regulatory approval, which was obtained in November 2020. Work has also commenced to onboard PMO and business integrator support, with additional procurement events planned for the communications network, meter / module installation, the CEMP, as well as IT infrastructure and cybersecurity. Each of these components is described in additional detail in Table 7-2.

Table 7-2: AMF procurement area descriptions

Procurement Area	Description
Initial RFS Components	AMF meters and gas modules, FAN communications equipment, HES, MDMS, and associated professional services
PMO	Professional services to support the Company in the management of the project
CEMP	Personalized integrated web-based platform that utilizes AMF data to educate and engage customers in managing energy use and costs
Business Integrator	Professional services supporting integration of AMF with the Company's existing systems, including delivery development, testing, and implementation of the overall AMF solution
IT Infrastructure & Cybersecurity	IT infrastructure components and a suite of cybersecurity services that are needed in addition to the initial RFS solution components to support the overall AMF solution
Communications Network	Procurement of WAN services, equipment and installation
Meter / Module Installation	Field support services to install meters and modules

7.4. Multi-jurisdictional Considerations

National Grid's multi-jurisdictional footprint offers a local utility focus coupled with large utility learnings and efficiencies. As mentioned, the Company's upstate New York affiliate received regulatory approval for its AMI proposal in November 2020. That effort, along with potential future opportunities to advance AMF in National Grid's Massachusetts jurisdiction, affords the Company and its customers an opportunity to leverage lessons learned from affiliate deployments while also capturing multi-jurisdictional cost synergies.

Figure 7-7 shows the illustrative timelines of AMF planning and deployment in National Grid's affiliate jurisdictions assuming regulatory approvals are achieved at the indicated illustrative dates. Of note is the overlapping period for development of back-office and system implementation in Rhode Island and New York, which is followed by overlapping meter deployment in the two states. The overlapping periods allow for synergistic learning and potential cost savings. To calculate the potential cost synergies in the BCA, the Company assumes the affiliate jurisdictions would implement the same technology on a similar timeline. However, if the approvals and deployments are staggered or involve different technological requirements, the realization of such synergies may change.

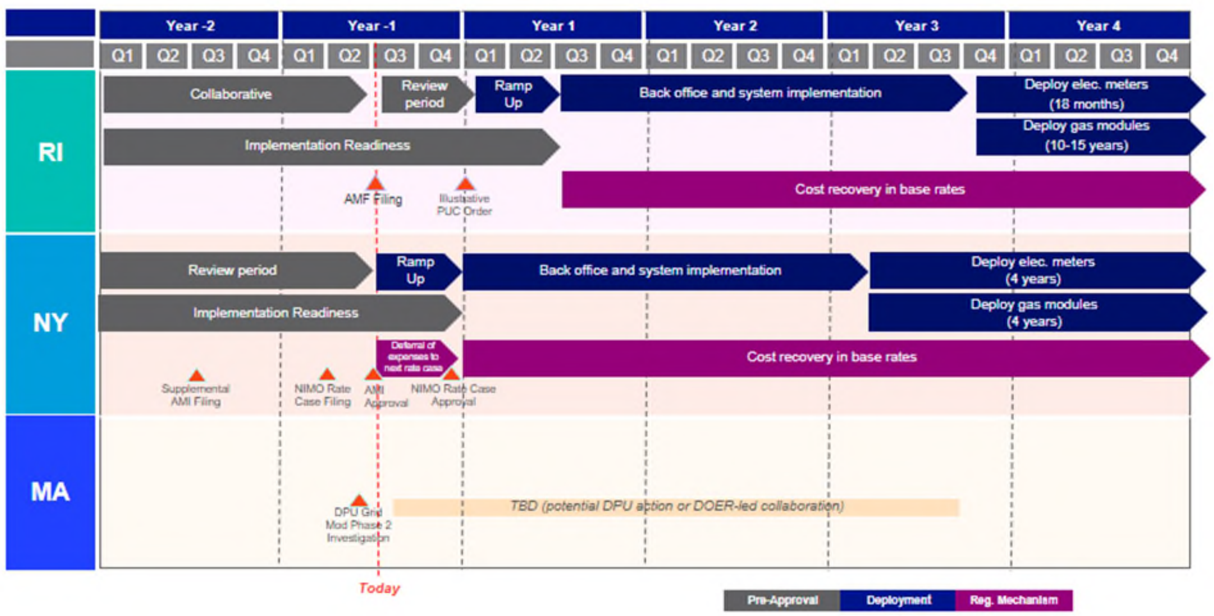


Figure 7-7: Illustrative multi-jurisdictional timeline of AMF-related activities

Similarly, Table 7-3 provides a brief overview of the AMF activity across National Grid's affiliate jurisdictions.

Table 7-3: Summary of AMF/AMI activity in affiliate jurisdictions

	Rhode Island	New York	Massachusetts
Company	Narragansett Electric Company	Niagara Mohawk Power Corporation	Massachusetts Electric Company and Nantucket Electric Company
Latest Business Case Filing	Docket No. 4770, Narragansett Electric Company Application to Change Electric and Gas Base Distribution Rates; Docket No. 4780 Proposed Power Sector Transformation (PST) Vision and Implementation Plan (November 27, 2017).	The NYPSC approved NMPC's AMI proposal on November 20, 2020 in Case Nos. 17-E-0238 and 17-G-0239.	D.P.U. 15-120, Petition of for Approval by the Department of Public Utilities of its Grid Modernization Plan (May 2017).[91]
Approx. Electric Meters	525,000	1,700,000	1,300,000
Approx. Gas Modules	277,000	640,000	*
Projected Meter/Module Deployment Date	2023	2023	N/A
Proposed Timeframe for Meter Deployment	1.5 years	4 years	3 years
FAN	Mesh	Mesh	Mesh
Deployment	Full Electric and Gas**	Full Electric and Gas	Full Electric
Proposed Rates	Illustrative TOU/CPP rate used for BCA	Illustrative TOU/CPP rate used for BCA[92]	Opt-out TOU/CPP
Meter Opt-in / Opt-out	Opt-out	Opt-out	Opt-out

* Gas not part of original filing but will be revisited in future filings.
** Gas modules are to be replaced as part of normal life-cycle replacement over a 10- to 15-year period.

[91] *See* Vote and Order Opening Investigation.

[92] Note the NYPSC did not approve a TVR as part of the NY AMI Order; rather, it deferred consideration of innovative pricing proposals to other pending dockets, while noting it is an important part of the suite of AMI benefits.

Multi-jurisdictional scenarios allow the Company to draw upon the experiences, internal expertise, and shared savings across its affiliates, while crafting an AMF solution that best addresses the needs of its Rhode Island customer base. Moreover, deployment across multiple jurisdictions creates potential cost synergies, including fixed cost sharing opportunities and increased purchasing scale such as:

- **Meter Equipment:** Additional volume discounts if there are common meter and telecommunications specifications, vendors, and meter deployments scheduled within the same time frame.

- **Communications System:** Opportunities to scale and share communication links between National Grid operating companies and SaaS providers. In addition, if common equipment specifications and vendors are utilized for communication equipment installed at substations, the potential exists for procurement synergies through volume discounts.

- **Information Management and Advanced Analytics:** Developing a common front end for data analysis and visualization to accommodate different data structures in the jurisdictions. Additionally, standard data models may be developed to manage master data.

- **Head-End System (HES):** Procuring hardware and software for both jurisdictions from the same vendors.

- **Cybersecurity:** Unit cost synergies for hardware, software and licenses, synergies in delivery/deployment of new security services, and reduced overall resources to maintain the comprehensive portfolio of core and supplementary security services.

- **Meter Data Management System (MDMS):** Procuring hardware and software for both jurisdictions from the same vendors.

- **Project Management:** Vendor Program Management, Business Process Design/Requirements Definition, Solution Architecture, Requirements Management, Organizational Change Management, Testing Management, Deployment Operations, and Performance Monitoring.

- **Data Lake:** Integration of corporate and operational data from legacy information systems in a common fashion to support AMF initiatives with the use of cloud services and labor for the development of foundational elements of a data lake to be leveraged across jurisdictions.

- **IT Infrastructure:** An ESB developed with a common architecture and deployed in both jurisdictions. Synergies can be derived in common foundational work prior to deployment.

- **IT Platform / System Testing / and Enterprise Architecture:** System testing may produce synergies in early strategy development for shared systems as well as in the coordination of testing during deployment in each jurisdiction.

Section 8.2.1 discusses the anticipated effect of these multi-jurisdictional synergies on the AMF program costs for Rhode Island should the state co-deploy AMF with New York.

7.5. Impact on Existing Customer Programs

The Company recognizes the deployment of smart metering as a unique opportunity to accelerate the evolution its existing portfolio of customer-facing programs and services, ranging from offerings such as residential and commercial EE and DR programs to its comprehensive electric transportation initiative. The deployment of AMF will also animate the market for third-party technologies and services, providing opportunities for third-party innovation and delivering additional benefits for customers under policies and programs set forth by state laws and regulations.

To that end, the Company has undertaken efforts to ensure that AMF serves a supporting and enabling role by which the Company, with enhanced customer insights, can better design, target, and implement its key customer-centric offerings. The Company believes that AMF is a critical component to achieving its long-term strategic vision for Rhode Island electric and gas customers, helping to maximize benefits and reduce costs. Grounded in the refreshed and personalized customer strategy, and along with ongoing investments in key customer engagement capabilities (particularly on the digital front), deployment of AMF serves as the critical step that best positions Rhode Island to attain the customer-facing objectives defined in Docket 4600 and the PST.

The Company will also take meaningful steps to ensure that benefits are not double counted and that costs are allocated and recovered appropriately. The Company envisions that all future program filings (e.g., EE plans) will leverage AMF, revising budgets and savings estimates to account for more efficient program delivery. The anticipated overlap and integration points with other customer programs are noted below in further detail. In total, the Company believes it has taken a conservative approach to assumptions around integration benefits with other programs, and it will seek to identify additional pools of customer-centric benefits as it deploys AMF.

7.6. Energy Efficiency (EE)

The availability of AMF-enabled interval usage data offers immediate incremental benefits for the Company's long-standing EE programs in service of its residential, income-eligible, small business, and large C&I customers, primarily in the form of more personalized targeting, action-based and programmatic recommendations, as well as potential enhancements to future evaluation, measurement, and verification (EM&V).[93] A further description of the integration in outreach strategies between AMF and the EE programs is included in the CEP.

The benefits estimated in the AMF BCA are based on initial customer savings that would occur when customers have visibility into enhanced energy insights and access to future TVR pricing. The savings assume customers have a smart meter paired with the CEMP; they do not assume access to other programs. The identified savings help to establish a new baseline upon which future EE program targets and forecasted savings are based. For example, the Company's existing Home Energy Reports program captures electric and gas savings that stem from customer behavioral change upon receipt of personalized energy reports with social norm comparisons. The methodology is similar to that which the Company uses to estimate customer response to the immediate availability and presentment of granular usage information that stems from deployment of AMF. In EE plans occurring after the deployment of AMF, the Company will incorporate this new baseline to determine what incremental savings can be achieved through Home Energy Reports and other programs. This will ensure that future EE programs are only counting incremental savings directly tied to clear programmatic efforts.

In addition to calculating benefits, the Company also examined potentially overlapping costs. Once AMF is deployed, the Company expects EE programs will continue to include customer incentives for in-home/in-business technologies, such as Wi-Fi programmable thermostats and smart appliances to drive the achievement of additional incremental energy savings to meet annual energy savings targets. The Company recognizes that the future EE plans will include the total participant costs (i.e., ratepayer-funded rebates and customer contribution costs) associated with such measures in its BCA methodology, and thus it is imprudent to include any additional estimated costs for these enabling technologies within its AMF BCA. The Company envisions that foundational AMF-enabled insights plus ongoing EE program-addressed adoption of energy-saving tools and products is the most appropriate path forward that greatly reduces any conflicts of interest or methodological complexity.

This Updated AMF Business Case will only use the benefits and costs specific to AMF deployment and will not count the costs and benefits that will be filed with future EE plans. The Company anticipates that the direct need to bifurcate savings and costs will not arise until AMF deployment begins and data is collected and visualized for customers, which will begin in AMF

[93] The Company does not estimate any EM&V-related benefits as part of its AMF BCA, although it recognizes that such a benefit may exist in the long-term.

year 3. Therefore, the important overlap and distinction between AMF and the EE Plans will most likely not arise until the after the period covered by the Company's current EE plans, when the Company anticipates a more robust discussion of evaluation methodologies and other key considerations. This effort will also look to leverage the ongoing collaboration of the Company and other participatory parties/stakeholders within the Energy Efficiency Resource Management Council and the EE Technical Working Group.

7.7. Demand Response (DR)

Building on the EE programs, both residential and commercial DR programs play a critical role in achieving system-wide peak reduction. The deployment of AMF will establish a basis for the implementation of TVR, providing improved price signals to traditional DR programs. The AMF BCA does forecast and capture customer benefits due to energy conservation during critical-peak periods. Therefore, the Company envisions future detailed exercises that properly address any potential instances of double counting of savings and benefits, as well as ensuring that overcollection of customer programmatic funds does not occur. As part of future DR program design, implementation, and evaluation, the Company will, in partnership with other interested stakeholders, undertake extensive analysis to clearly separate achieved benefits that stem from AMF deployment and the Company's ongoing DR initiatives.

Additionally, TVR provides an economic incentive to encourage adoption of traditional DR technologies as well as new DERs, such as behind-the-meter energy storage, that can provide valuable contributions to DR programs. TVR will also allow for more creative DR program design in the future, leveraging advanced rate structures or more geographically granular peak reduction programs, including potential for DER-specific rates. DR program design can further be expanded to include additional grid services, such as voltage regulation support, and targeted deployments to support feeder-specific NWA projects.

7.8. Electric Transportation

The Company is currently implementing a comprehensive electric transportation initiative approved in Docket No. 4780. The initiative, which is geared generally toward improving customer adoption and utilization of EVs, is not included in the Company's AMF benefits forecast in terms of helping to accelerate EV adoption. However, due to the enabling functionality of AMF to implement TVR, the Company does envision a quantitative benefit for AMF in helping to shift EV charging patterns to periods when energy is less expensive. As such, the AMF BCA does include estimated benefits due to customers shifting EV charging patterns, thereby reducing their total ownership costs while helping to prevent additional electrical load during on-peak or critical-peak periods.

The Company has developed and implemented the SmartCharge RI pilot, running through August 2021 in partnership with FleetCarma, to study the charging behaviors of residential EV owners. The pilot program will inform future full-scale programs using AMF. However, unlike the current pilot, future AMF-enabled programs are likely to include offerings for commercial customers, such as workplaces, multifamily housing, public parking, and retail locations, as well as commercial fleets. AMF will also provide the data necessary to develop analytics to better inform, develop, and implement electric transportation programs. For example, applications can detect which customers are charging an EV at their home, determine the size of a customer's EV charger, and understand charging patterns. Program management tools such as these will provide the ability to develop targeted marketing and enrollment of customers into future EV-specific offerings and deliver scalable analytics to design effective EV rate plans.

8. BCA Evaluation Under Docket 4600

This section presents the results of the BCA conducted by the Company to determine the cost effectiveness of full-scale AMF deployment consistent with the Docket 4600 Framework. This section begins with a presentation of high-level results and includes detailed descriptions of the elements that compose the results. The Company has isolated the effects of benefit considerations that are incremental to the past results presented in its PST Plan filing in Docket No. 4780 to emphasize the impact of fully applying the Docket 4600 Framework to the BCA.

Unless otherwise noted, BCA results shown throughout this section use forecasts consistent with the High DER Adoptions scenario described in the GMP. This is the forecast that complies with Rhode Island's 40 x 30[94] emissions targets.

8.1. BCA Overview

The summary results of the BCA[95] appear in Figure 8-1 showing BCA ratios for the Base Case scenario of 2.38 (assuming the midpoint of the opt-out TVR scenario) and 1.91 (assuming the midpoint of the opt-in TVR scenario), respectively. The red bar represents the cost of the program, while the turquoise bar represents the benefits of the program, taken to be the midpoint between high and low customer response cases. The customer response cases bookend the extent to which customers respond to usage and price signals with conservation and load shifting. Error bars on the benefits show the range of benefits that result from the high and low customer response cases. The details of the TVR participation, deployment, and customer response cases

[94] The Company's goal of 40% reduction in GHG by 2030 (40 x 30) is aligned with the Resilient Rhode Island Act's goal of 45% reduction by 2035. The Company believes an interim 40 x 30 goal is necessary to achieve the end goal, as laid out in the Resilient Rhode Island Act, of 80% reduction in GHG emissions by 2050. This assumption is also applied in the GMP.

[95] The confidential Updated AMF BCA is included as Attachment E.

are discussed in Section 8.2.1. Detailed cost and benefit numbers are provided in Sections 8.3 and 8.4, respectively.

Furthermore, the Company does not believe the cost effectiveness of the AMF program will be meaningfully affected by customer migration to third-party energy suppliers. Research into jurisdictions with well-established third-party suppliers indicates that TVR participation is unlikely to drop below the level tested in the opt-in case.[96]

Given the breadth of the Docket 4600 Framework, the proposal achieves cost-effectiveness by leaning on the many benefits that do not require widespread participation in TVR. This is discussed in greater detail in Appendix 10.4.4. Figure 8-2 unwinds the NPV calculation in Figure 8-1 by showing the stream of annual costs and benefits over the 20-year analysis period for the opt-out case. Again, the error bars are determined by alternative deployment and customer response cases.

Most AMF costs appear in the first four years of project implementation. Years one and two of this time consist of costs associated with setting up back-office and IT systems to support the new meter functionality. Years three and four show a spike in costs associated with the actual meter capital and installation cost with the meter deployment. Corresponding to this electric meter deployment schedule, large benefits from avoided AMR costs appear in years three and four as well. Following meter installation, O&M savings are anticipated in every year thereafter. Later year benefits increase with the phasing in of TVR and customer participation/response to price signals reaches a steady state. Later year costs consist of only those to sustain the program. Based on this stream of costs and benefits over time, the AMF program has a payback period of 6.3 years.

To mitigate bill impacts to customers based on the timing of benefit achievement and to facilitate earlier realization of benefits, the Company proposes an upfront adjustment to the proposed revenue requirement in the first rate period following AMF approval by incorporating 80% of the Non-OMS Avoided O&M Cost benefit. This commitment provides an incentive for the Company to ensure the benefits are achieved in a timely manner, as there is a financial risk tied to failing to deliver them (i.e., the Company would be collecting less money than the expenses it is incurring).

[96] Data obtained via email correspondence with ERCOT indicates that 18% of residential customers in Texas were on TVR in 2018, six years after smart meter deployment.

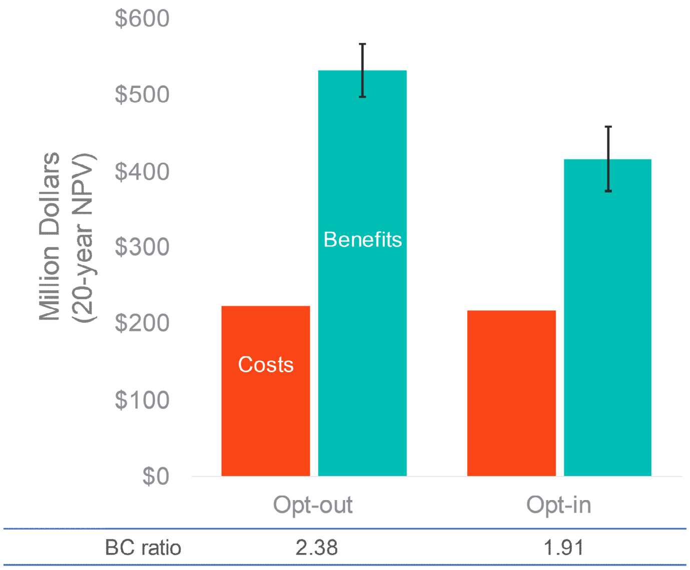


Figure 8-1: NPV costs and benefits of the opt-out and opt-in scenarios. Upper and lower bounds of benefits defined by high and low customer response cases (bar corresponds to midpoint)

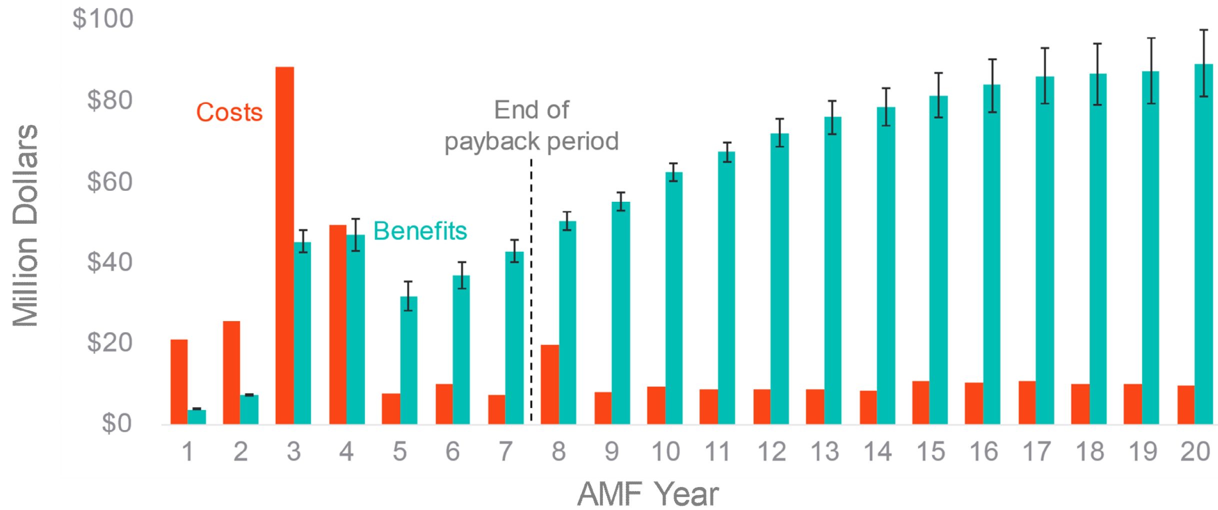


Figure 8-2: Costs and benefits over the 20-year analysis period for the opt-out scenario. Upper and lower bounds of benefits defined by high and low customer response cases (bar corresponds to midpoint)

The analysis presented in this Updated AMF Business Case differs from that presented in the 2017 PST Plan in several respects. First, the Company updated forecasts of key inputs to the benefits, refined the costs based on RFS efforts, and reevaluated some calculation methods. Second, the expanded application of the Docket 4600 Framework resulted in a more complete list of benefits. The waterfall chart in Figure 8-3 compares the benefit elements of this filing to those used previously.

The "Original 2017 Benefits" and "Updated 2017 Benefits" columns in the chart compare categories that are common to both filings. The latter of these shows the same benefit categories as were included in the 2017 filing updated to include the most recent forecasts and methodologies.[97] From the "NOx & SOx" column onward, the chart recognizes the impact of new benefit categories from the Docket 4600 Framework. The benefits and benefit-cost ratio presented for the opt-out case of Figure 8-1 comes from the rightmost column that includes all elements of the waterfall. The definition of this Docket 4600 Framework is discussed in Section 8.2, and Section 8.5 continues to describe its impact on the BCA.

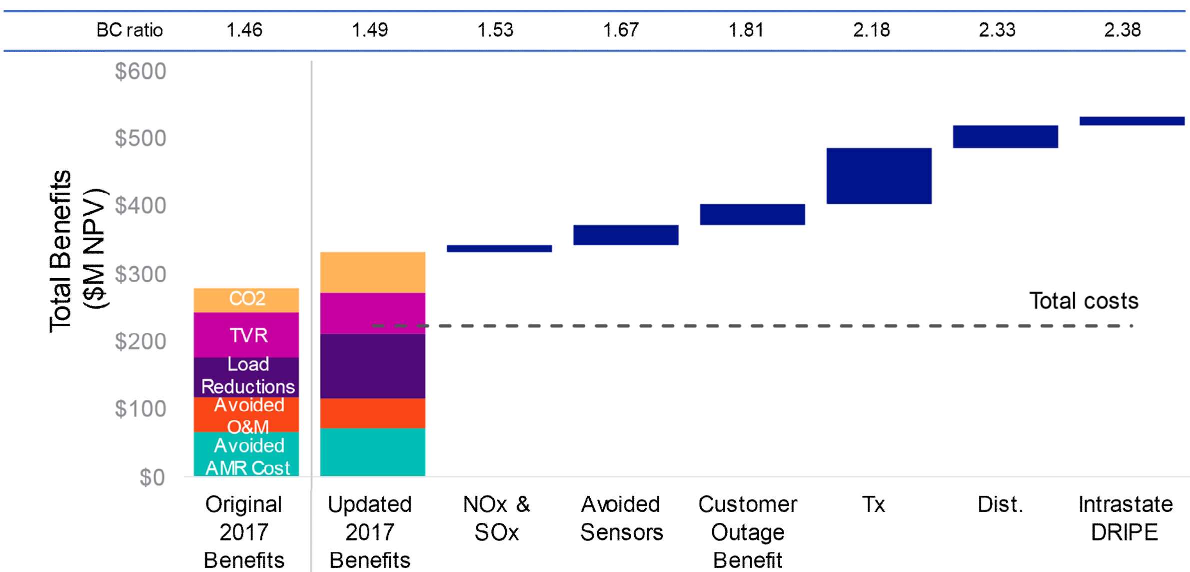


Figure 8-3: <u>Opt-out</u> benefits broken out by category. Categories in the stacked bars are categories that were included in the 2017 BCA. Categories in the waterfall are new to the BCA in this filing

[97] Input updates include more recent information on items such as pre- and post-tax weighted average cost of capital (WACC), the non-labor escalation rate, vehicle costs, FTEs for project management and support, EV adoption forecasts, heat pump adoption forecasts, savings levels from Energy Insights/Bill Alerts, avoided costs of energy and capacity, forecasts of load and demand, and emissions costs. Methodological updates include use of time-varying emissions factors, more sophisticated TVR impact calculations and elasticities, limiting EV load shifting impacts by TVR participation, and consideration of both embedded and non-embedded CO_2 costs.

8.2. Docket 4600 and the Rhode Island Test

The cost-effectiveness test on which the Docket 4600 Framework is based is known as the "Rhode Island Test." The Rhode Island Test considers benefits to the power system, the customer, and certain societal impacts. Because the Rhode Island Test is intended for evaluating a variety of programs, the Docket 4600 Framework includes a wide array of categories for consideration – some of which will be relevant depending on the proposal.[98] In this Section, the Company explains how it applies the Docket 4600 Framework for the purposes of this Updated AMF Business Case.

The Docket 4600 Framework attempts to quantify whether the state of Rhode Island will be better off adopting a proposed program. The benefits assessed under the Docket 4600 Framework include operational utility benefits, customer benefits, reductions in resource requirements (e.g., transmission and distribution, generation capacity, and energy use) and reductions in externalities such as carbon emissions. Expenses borne by the utility or its customers appear as costs in the BCA. Transfers of money between the utility and its customers or between different customer groups are internal to this cost definition and therefore do not appear in the BCA.

The benefit categories used throughout this section are based on AMF capabilities, such as the ability to read meters remotely or implement TVR for mass market customers. To tie these benefit categories to the more generalized Docket 4600 Framework, Table 8-1 lists the AMF benefits associated with each quantified Docket 4600 category. Along with this listing are the values in millions of dollars for each Docket 4600 category calculated in the BCA. More specific explanations of the costs and benefits considered by the BCA appears in Sections 8.3 and8.4, as well as in Appendix 10.5.

Table 8-1: Docket 4600 Framework categories quantified in the BCA model

Docket 4600 Category	Estimated Value: Opt-out/Opt-in Case Midpoint ($M)	AMF Benefits in BCA
Distribution Delivery Costs (Power Sector Level)	142.17	AMR Meter Reading Meter Investigation Remote Connect/Disconnect Other Meter Reading Avoided AMR Capital Avoided AMR O&M Avoided Feeder Sensors

[98] *See* Presentation of Staff Workshop on PUC's Docket 4600-A Guidance Document (November 1, 2018).

Docket 4600 Category	Estimated Value: Opt-out/Opt-in Case Midpoint ($M)	AMF Benefits in BCA
Energy Supply & Transmission Operating Value of Energy Provided or Saved (Power Sector Level)	64.23 / 61.85	Energy Insights / Bill Alerts EV Pricing TVR
Renewable Energy Credit (REC) Value (Power Sector Level)	0.00 / 0.00	VVO Energy Insights / Bill Alerts EV Pricing TVR
Retail Supplier Risk Premium (Power Sector Level)	10.69 / 8.01	VVO Energy Insights / Bill Alerts EV Pricing TVR
Forward Commitment Capacity Value (Power Sector Level)	53.54 / 19.81	VVO EV Pricing TVR
Electric Transmission Capacity Value (Power Sector Level)	83.26 / 30.54	VVO EV Pricing TVR
Energy Demand Reduction Induced Price Effect (DRIPE) (Power Sector Level)	11.27 / 5.89	VVO Energy Insights / Bill Alerts EV Pricing TVR
GHG Compliance Costs (Power Sector Level)	7.96 / 7.77	VVO Energy Insights / Bill Alerts EV Pricing TVR
Distribution Capacity Costs (Power Sector Level)	33.60 / 16.16	VVO EV Pricing TVR
Distribution System Performance (Power Sector Level)	26.52	VVO
Utility Low Income (Power Sector Level)	7.62	Reduction in bad debt write-offs (Sensitivity)
Distribution System and Customer Reliability/Resilience Impacts (Power Sector Level)	32.60	Storm OMS Benefit Outage Management (Societal)

Docket 4600 Category	Estimated Value: Opt-out/Opt-in Case Midpoint ($M)	AMF Benefits in BCA
Distribution System Safety Loss/Gain (Power Sector Level)	3.85	Reduced Damage Claims
Non-participant Rate and Bill Impacts (Customer Level)	N/A	(Reported separately from BCA)
GHG Externality Cost (Societal Level)	53.87 / 53.04	O&M CO_2 Savings EV Pricing Societal Benefit Energy Insights / Bill Alerts Societal Benefit VVO Societal Benefit TVR Societal Benefit
Criteria Air Pollutant and Other Environmental Externality Costs (Societal Level)	1.48 / 1.40	EV Pricing Societal Benefit Energy Insights / Bill Alerts Societal Benefit VVO Societal Benefit TVR Societal Benefit
Non-energy benefits: Economic Development (Societal Level)	115.86	Economic Development (Sensitivity)
Public Health (Societal Level)	7.46 / 6.61	EV Pricing Societal Benefit Energy Insights / Bill Alerts Societal Benefit VVO Societal Benefit TVR Societal Benefit

To capture the value of AMF over time, the BCA considers an analysis timeframe of 20 years, which corresponds to the AMF solution lifetime including back-office system development. The Company believes this is an appropriate given the time for meter installation and the manufacturers estimated meter life of 20 years. This is critical to understanding the full value of AMF; while many costs appear in early years as meters are installed and back-office systems are set up, benefits tend to accrue later as TVR rates roll out, electrified loads increase, and customers engage more with their energy usage.

Total benefits and costs are shown on an NPV basis using the 20-year term, end-of-period cash flows, and a discount rate equal to the Company’s after-tax Weighted Average Cost of Capital (WACC) of 6.97%. Use of the WACC recognizes that many BCA elements are capital expenditures incurred or avoided by the Company and results in a more conservative analysis due to benefits accruing over the long term. The after-tax value is used because taxes are considered income transfers within the state and are therefore excluded. For the AMF proposal, this calculation is also referred to as the Rhode Island Test.

The Company, with input from stakeholders in the PST Advisory Group, developed this approach based on the Docket 4600 Framework. During this engagement, some stakeholders indicated preferences for elements of the Rhode Island Test that were not aligned with the Company's approach. In the interest of capturing these differing opinions, the Company includes alternative BCA formulations in Section 8.6 showing how incorporating the proposed alternatives would affect the BCA. Only one of these alternative formulations (the non -policy-compliant Low DER Adoption scenario) results in a decrease to the BCA ratio presented here.

8.2.1. BCA Sensitivities

The Company notes that some critical elements that feed into the AMF BCA lie outside of its control. For example, customer behavior, although capable of being influenced by marketing, education, and outreach campaigns, is not within the Company's control.

To capture the uncertainty of these unknown and largely uncontrollable factors, the BCA presents four cases meant to bookend possible benefit outcomes. The cases are outlined in Table 8-2. They include sensitivities around TVR enrollment and customer responses to TVR and usage insights / bill alerts. The Company includes these sensitivities because the assumptions are considered the most uncertain of assumptions with large impacts; while other uncertainties exist, none are expected to have as large an effect on the BCA as these. Each of the cases is explained in more detail below.

Table 8-2: Cases presented in the AMF BCA (based on a 20-year NPV). Note that most results shown correspond to the midpoint between high and low customer response cases and therefore do not appear directly in this table. The highest BCA ratio comes from case 4 and the lowest from case 1.

Case	1	2	3	4
TVR Enrollment	Opt-in	Opt-in	Opt-out	Opt-out
Customer Response	Low	High	Low	High
Costs ($M)	$217.91	$217.66	$224.70	$222.66
Benefits ($M)	$373.88	$458.53	$498.19	$566.81
BC Ratio	1.72	2.11	2.22	2.55

TVR Enrollment

The TOU/CPP supply rate used in the BCA consists of a four-season, two-period (on-peak, off-peak) TOU rate and a separate CPP rate. The TOU rate is based on, and captures variation in, Independent System Operator-New England (ISO-NE) energy market prices. The CPP rate includes all generation capacity costs, allocated over 70 hours per year. Based on the Company's expected duration of CPP events, this equates to approximately 12 to 15 events per year.

Many factors affect the number of customers that enroll in TVR. Regulatory policy will dictate whether TVR will be offered on a default service basis (opt-out) or not (opt-in). Even within either TVR structure the number of customers who participate will vary. The BCA presents results on both opt-out and opt-in bases, assuming 85% and 20% participation, respectively. Consistent with findings in other jurisdictions, the BCA model results show that an opt-in approach results in higher TVR benefits per enrolled customer, but an opt-out approach results in higher TVR benefits overall.

The opt-in value is consistent with findings from the Sacramento Municipal Utility District (SMUD)[99] and the DOE,[100] while opt-out values are more conservative than the 10% to 14% opt-out range seen by Ontario, Canada[101] and the California investor-owned utilities.[102] Moreover, the opt-out assumption is considerably lower than the 98% participation rate the Company observed in its Worcester Pilot.[103]

Given an opt-out design, some customers will choose to receive supply service from third-party suppliers, such as Community Choice Aggregators (CCAs) who may offer flat rates. This may cause attrition below the assumed opt-out participation rate. However, given that 20% of customers (the opt-in participation value) are assumed to opt into non-default TVR rates, the Company assumes that default service participation would not fall below the 20% level.

In the jurisdictions that have fully implemented (Ontario, Canada) or piloted (California) opt-out TVR, customer migration has been relatively limited. In Texas, which has full retail competition and no default service utility, third-party suppliers offer TVR rates, and nearly 20% of customers chose some form of TVR by 2018 – five years after the completion of AMF deployment in the state. In Rhode Island, the Company has engaged with NPPs, who have indicated they will look to provide a TOU rate when smart metering is installed. This is consistent with recent evidence from California suggesting that where the incumbent utility offers TVR as the default, CCAs follow suit, providing customers a similar experience.[104] Additional detail on the Company's consideration of TVR for this filing is available in Appendix 10.4.

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[99] Smart Grid Investment Grant, Consumer Behavior Study Analysis, *Time-of-Use as a Default Rate for Residential Customers: Issues and Insights* (June 2016).

[100] U.S. Department of Energy, Lawrence Berkeley National Laboratory, *American Recovery and Reinvestment Act of 2009: Final Report on Customer Acceptance, Retention, and Response to Time-Based Rates from Consumer Behavior Studies* (November 2016); *see also* 2017 NY Rate Case, *supra* note 36, Prepared Testimony of the Staff Advanced Meter Infrastructure Panel at 27 (August 25, 2017) ("Exhibit ___ (SAMIP-5) contains a report of DOE sponsored customer behavior studies from 2016 in which 10 utilities ran rate pilots. According to this report, opt-in programs had an average participation rate of 15%, versus 93% for opt-out programs.").

[101] Navigant, *Time-of-Use Rates in Ontario, Part 1: Impact Analysis* (2013).

[102] Nexant, *California Statewide Opt-in Time-of-Use Pricing Pilot: Final Report* (2018).

[103] *See* Appendix 10.8 for more information regarding the Worcester Pilot.

[104] *See* Marin Clean Energy rate EOTOU-C versus PG&E TVR offerings.

Customer Response

The extent customers alter their energy usage in response to price signals and improved knowledge of their usage also comes with uncertainty. A survey of substitution elasticities[105] in response to TOU and CPP rates found values ranging from -0.5%[106] to -18%.[107] Notably, the aggregate response values depend on whether the rate offered was opt-in or opt-out. Generally, an opt-in population is more responsive to price signals because they are a self-selected group who are choosing to engage with their energy usage.[108] In Clifton Park, the Company's New York affiliate has likewise seen that more engaged customers tend to respond more to price signals.

The BCA model includes high- and low-customer response cases for each TVR enrollment case to account for customer price response uncertainty. Taking the example of a TOU/CPP rate, a high customer response compared to a low customer response means:

- A larger decrease in on-peak energy usage due to the on-peak rate;
- A larger corresponding increase in off-peak energy usage due to the off-peak rate;
- An equivalent decrease in peak demand due to CPP pricing (explained below);
- A larger decrease in total usage due to energy insights and bill alerts; and
- A longer phase-in time to achieve these steady-state response levels.

This last point is meant to emphasize that customers will take some number of years to settle into consistent usage patterns as they adjust to new rate structures and availability of detailed usage information. This time is assumed to be shorter for opt-in cases due to the advanced understanding/engagement of TOU rates for these customers.

[105] Substitution elasticities indicate by what percentage the on/off-peak consumption ratio changes for every 1% change in the on/off-peak price ratio.

[106] *See* Faruqui, A., Lessem, N., Sergici, S., Mountain, D., Denton, F., Spencer, B., King, C., *Analysis of Ontario's Full Scale Roll-out of TOU Rates – Final Study* (2016).

[107] *See* Potter, J., George, S., Jimenez, L., Smart Pricing Options Final Evaluation: The final report on pilot design, implementation, and evaluation of the Sacramento Municipal Utility District's Consumer Behavior Study (2014).

[108] *See Id*.

Table 8-3: Assumptions for energy usage shifting and savings in BCA cases

Case	Elasticity	On-peak energy reduction	Off-peak energy increase	Peak demand reduction	Energy Insights conservation	Years to steady state
Opt-out Low	-0.06	1.8%	0.8%	20%	1.5%	5
Opt-out High	-0.10	3.0%	1.3%	20%	3.5%	10
Opt-in Low	-0.10	3.0%	1.3%	20%	1.5%	2
Opt-in High	-0.18	5.4%	2.4%	20%	3.5%	5

The details of the assumptions used for the high- and low-response cases appear in Table 8-3, which lays out the different combinations of TVR enrollment and customer response along with the input assumptions that change for each of them. A description of the literature survey used to choose these elasticities appears in Appendix 10.4.

Peak demand reductions for enrolled customers do not change between cases. As explained in the Appendix, the CPP rate is high enough that customer response is maximized at any of the elasticities used. However, the differing enrollment rates among cases and timespans to achieve steady state savings mean that this 20% is applied to different levels of demand in each case. Most results shown throughout this section correspond to the midpoint between high- and low-customer response levels, with error bars often indicating the high and low extremes around the midpoint.

8.3. Costs

The AMF program consists of four key cost elements listed in Table 8-4 and described in additional detail in Appendix 10.5:

- An integrated system of smart electric meters and the installation thereof;
- A communications network and associated infrastructure;
- An IT platform for data collection and ongoing IT operations; and
- Customer systems including billing and a CEMP to provide energy usage data access, insights, and service offering to enable customer energy management.

Table 8-4 shows the NPV costs of these elements depending on the TVR enrollment scenario.

Table 8-4: AMF program costs by category listed for the TVR enrollment scenarios. Numbers shown are $M 20-year NPV.

Cost Category	Opt-out	Opt-in
AMF Meter and Installation	$86.01	$86.01
Communications Network Equipment and installation	$3.80	$3.80
Platform and Ongoing IT Operations	$74.46	$74.46
Customer Systems including billing and CEMP	$59.41	$53.51
Total	**$223.68**	**$217.78**

Costs differ by about 2% among different TVR enrollment and customer response cases (only the former shown here). While most cost components are unaffected by these cases, the cost of managing the TOU/CPP pricing is not. This cost is taken to be 20% of the avoided energy and demand savings from TVR; a conservatively high number based on industry expertise. This cost represents the marketing and operation cost of the TVR program. Because the differences in cost between the opt-out and opt-in TVR cases are small, the figures in this section depict only costs from the opt-out TVR case.

Cost reductions due to co-deployment with New York

In November 2020, the NYPSC approved the AMI proposal of the Company's upstate New York affiliate.[109] Should the PUC approve the AMF proposal set forth in this Updated AMF Business Case, Rhode Island and New York are expected to realize cost savings from sharing fixed costs, increased purchasing scale, and by sharing some full-time equivalent (FTE) employees among jurisdictions. In the case of cost sharing, total costs of each shared investment would be allocated between the two jurisdictions, which makes Rhode Island responsible for approximately one quarter of the cost of those specific elements. Shared resource FTE hours are subject to a 0.8 de-rate factor. Table 8-5 summarizes the various components where cost synergies can be realized along with factors driving the synergy. This cost allocation is consistent with the approved methodologies provided in the Company's service agreements with each affiliate, as outlined in the National Grid USA Service Company's (Service Company) Cost Allocation Manual. The costs presented in this Updated AMF Business Case assume the cost decreases due to co-deployment with New York.

[109] *See* NY AMI Order, *supra* note 4, at 52-53.

Table 8-5: Cost components that decrease with RI+NY deployment

Cost Component	Shared / One-state	Cost Synergy Driver
Electric Meters	One-state	Purchasing scale
Meter Data Management System (MDMS)	Shared	Purchasing scale
Head End Systems (HES)	Shared	Purchasing scale
Network Management System (NMS)	Shared	Purchasing scale
Project Management and other Full-Time Employee costs	Shared	FTE sharing
Enterprise Service Bus (ESB)	Shared	Fixed cost sharing
Customer Information Systems (CIS)	Shared	Fixed cost sharing
Customer Energy Management Platform (CEMP)	Shared	Fixed cost sharing
Telecom	Shared	Fixed cost sharing
Cybersecurity	Shared	Fixed cost sharing
Green Button Connect (GBC)	Shared	Fixed cost sharing
Data Lake	Shared	Fixed cost sharing
Information Management	Shared	Fixed cost sharing

AMF Meter and Installation Costs

This category includes the cost of smart electric meters, their installation, an inventory of meters, and the necessary support infrastructure. Gas module roll-out, on the other hand, will follow the timeline of BAU gas meter replacement. As such, gas module costs fall within the ISR filing – the incremental cost of the AMF-enabled gas modules is zero. Because this incremental cost is zero, there is no BCA element associated with the purchase or installation of gas modules. As shown in Figure 8-4, the equipment and installation cost of the electric meters accounts for the majority of the costs. This element is the single largest cost component of this Updated AMF Business Case and it does not vary across the TVR scenarios.

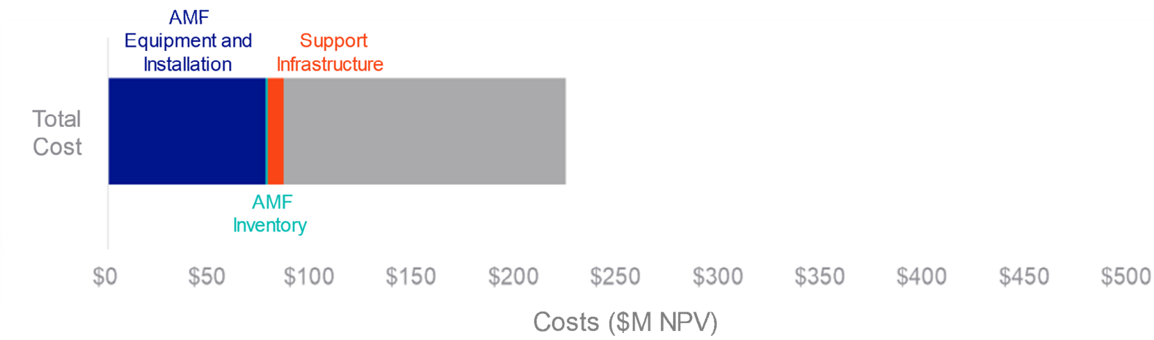


Figure 8-4: NPV costs of the opt-out case
AMF Meter and Installation Costs are highlighted.

Communications Network Equipment and Installation Costs

This category includes the communications network equipment, its installation, and the associated backhaul network costs for transmitting meter data. Though important, these costs are small compared to the other cost categories. Figure 8-5 highlights these costs among the total costs to show their relatively small contribution to the total.

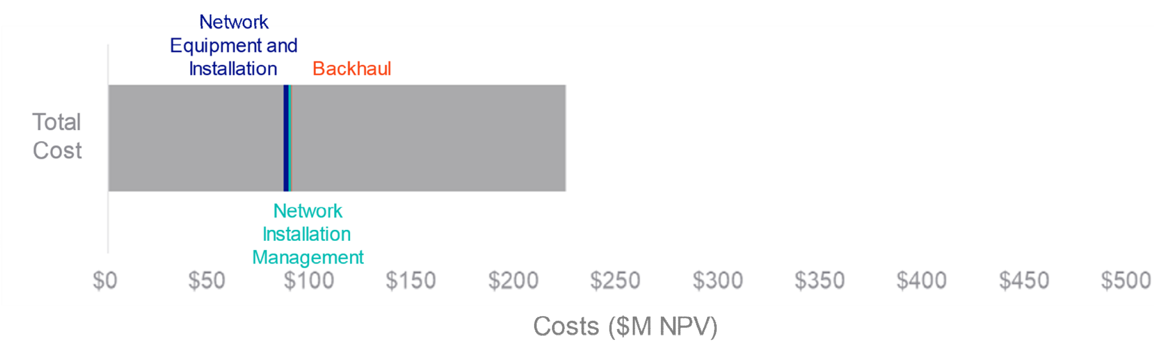


Figure 8-5: NPV costs of the opt-out case. Communications
Network Equipment and Installation Costs are highlighted.

Platform and Ongoing IT Operations Costs

This category includes the total cost of an IT platform for data collection, monitoring and control of the communication system; an expanded cybersecurity system; MDMS and HES; an analytics platform to convert raw data into intelligent information for use in decision making by customers and the Company; and customer engagement solutions. Figure 8-6 highlights the Platform and Ongoing IT Operations Costs, which are largely driven by the MDMS, HES, and IT infrastructure.

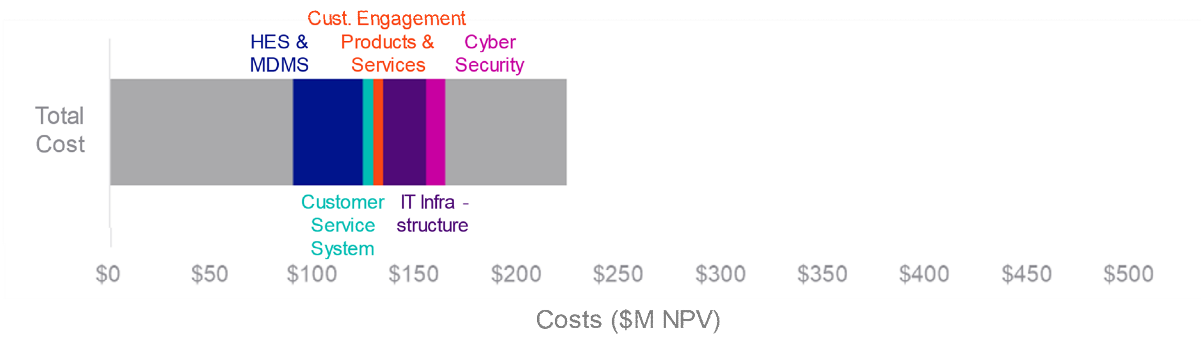


Figure 8-6: NPV costs of the opt-out case
Platform and Ongoing IT Operations Costs are highlighted

Customer Systems including billing and CEMP Costs

This category includes the cost of customer systems: comprehensive customer engagement, project management, ongoing business operations, equipment and installation refresh, and TVR implementation and administration. These components are shown in Figure 8-7. Project management and customer engagement costs are the largest cost elements of this category, and administration of the TVR is the only cost element to fluctuate depending on the customer response and TVR enrollment cases.

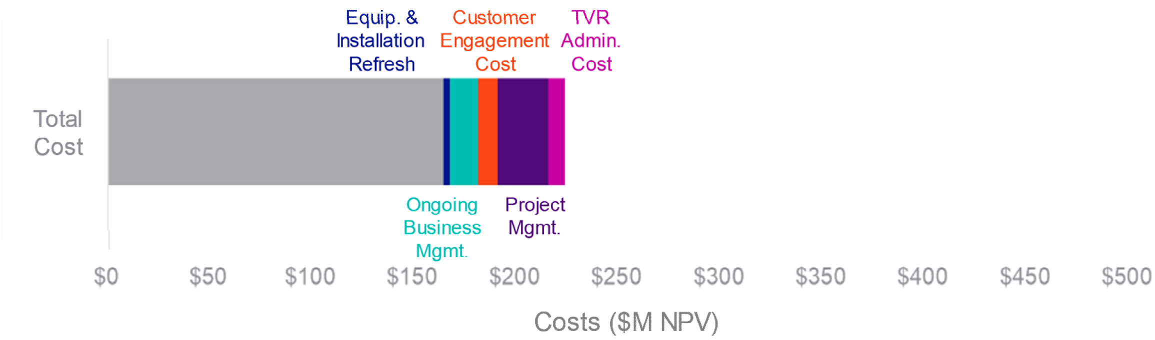


Figure 8-7: NPV costs of the opt-out case
Customer Systems including billing and CEMP Costs are highlighted

8.3.1. Cost Basis and Contingency

The Company has taken multiple approaches regarding program estimates to establish enhanced cost certainty. Primary to these efforts is an RFS for the core components of the AMF program encompassing the electric meters, HES, MDMS, FAN equipment, and professional support services. The Company also leveraged its experience with past large-scale meter deployments to help refine the estimates.

Figure 8-8 shows the AMF costs separated into 3 categories: 1) RFS (also discussed in Section 7.3.5); 2) IT; and 3) Non-IT, to provide additional insight into the basis for the cost estimates. The total contingency for the project is $11 million NPV, which represents approximately 5% of the total project costs.

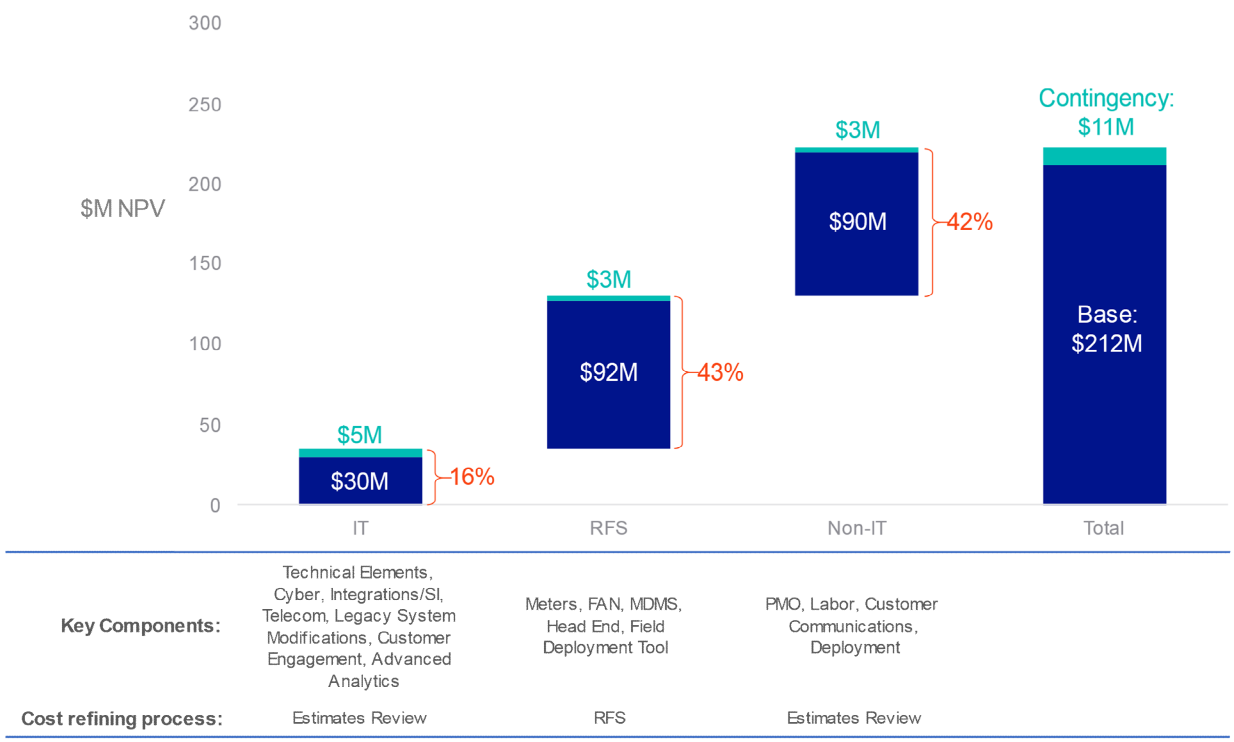


Figure 8-8: AMF Cost Basis and Contingency Breakdown (20-year, NPV)

Information Technology

The IT cost element consists of all costs associated with the back-office integration not covered under the RFS. This would also include cyber, data support, and the systems integration work. The Company included an additional 30% cost contingency to key stand up areas but did not apply the contingency to its operating expenses or run-the-business expenses.

Request for Solution

The RFS cost segment includes vendor-covered costs for the procurement event, spanning meters and gas modules to the software, and vendor labor for the configuration. The RFS process ensures that the vendor's proposal is responsive to the Company's solicitation, that the vendor is capable of meeting the Company's requirements, and that through negotiation and contract execution, the Company mitigates the risk of inadequate vendor performance. RFS costs in the model are the result of negotiations with the Company's down-selected vendor and therefore have a lower level of uncertainty. However, as the Company and vendor have not executed a contract, the RFS segment includes some contingency.

Non-Information Technology

All other costs fall under the Non-IT cost segment, including the PMO, training content creation and delivery, and any supplementary labor (e.g., additional call center representatives). The Company added an additional cost contingency to the higher variability elements within the Non-IT segment.

8.4. Quantified Benefits

For this Updated AMF Business Case, the Company categorized benefits into the following five segments, the first four of which are included in the Rhode Island Test:

- Avoided O&M costs;
- Avoided AMR Replacement Costs;
- Customer Benefits;
- Societal Benefits; and
- Non-quantified benefits not reflected in the BCA.

Table 8-6 shows the calculated NPV benefits for each of these categories for different TVR participation and customer response cases. The customer benefits category is the largest as it accounts for 60% of benefits in the TVR opt-out case (50% for opt-in). A large portion of the societal benefits are tied to customer benefits as well, since changes in customer usage drive decreases in emissions. As a result, these two categories vary with differing assumptions of TVR enrollment and customer response. On the other hand, the Avoided AMR and Avoided O&M benefit categories do not vary by case.

Table 8-6: AMF program benefits by category listed for different TVR enrollment / response scenarios (M 20-year NPV)

Benefit Category	TVR Opt-out Midpoint	TVR Opt-in Midpoint	TVR Opt-out Low	TVR Opt-in Low	TVR Opt-out High	TVR Opt-in High
Avoided O&M Costs	$45.30	$45.30	$45.30	$45.30	$45.30	$45.30
Avoided AMR Costs	$102.66	$102.66	$102.66	$102.66	$102.66	$102.66
Customer Benefits	$321.74	$207.20	$304.24	$181.56	$339.24	$232.83
Societal Benefits	$62.81	$61.05	$46.00	$44.36	$79.62	$77.74
Total Benefits	**$532.50**	**$416.20**	**$498.19**	**$373.88**	**$566.81**	**$458.53**

Enabling and delivering the forecast benefits is important to the Company and to stakeholders. In evaluating the certainty of the benefits estimates, customer response to AMF and AMF-enabled functionalities (a factor that can be influenced but not controlled by the Company) plays a key role in a large portion of the benefits calculations. Section 8.4.1 further discusses the importance of benefit realization and steps the Company has taken to understand the amount of realization required to ensure cost-effectiveness. Also, the Metrics and Performance Incentive Measures Roadmap (Attachment D) addresses steps to ensure benefit realization.

Avoided O&M Costs

AMF implementation allows the Company to avoid specific O&M costs, including: 1) AMR meter reading vehicles, personnel, and annual software and maintenance; 2) meter investigations; 3) a portion of the meter visits required to connect and disconnect[110] service; 4) damage claims; 5) outages; 6) the Field Collection System (FCS) for AMR meter reading; and 7) the MV-90 interval meter system. Figure 8-9 shows these benefits in the context of total project benefits. The largest benefits come from avoided truck rolls for AMR meter reading and labor cost savings based on the ability to use AMF to remotely read, connect, and disconnect service. The Remote Connect/Disconnect benefit is quantified based on labor-related savings. More detail on the specifics of this benefit appears in Appendix 10.5.

[110] Any disconnections will be done in compliance with applicable rules and regulations governing terminations of residential electric and gas utility services, including PUC orders and requirements, the Low-Income Home Energy Assistance Program (LIHEAP), and the Arrears Management Plan (AMP) program.

Achievement of many of the avoided O&M costs, such as avoided meter reading, are under the Company's control. Others, such as outages and damage claims are impacted by external factors like weather and service orders, which the Company cannot control.

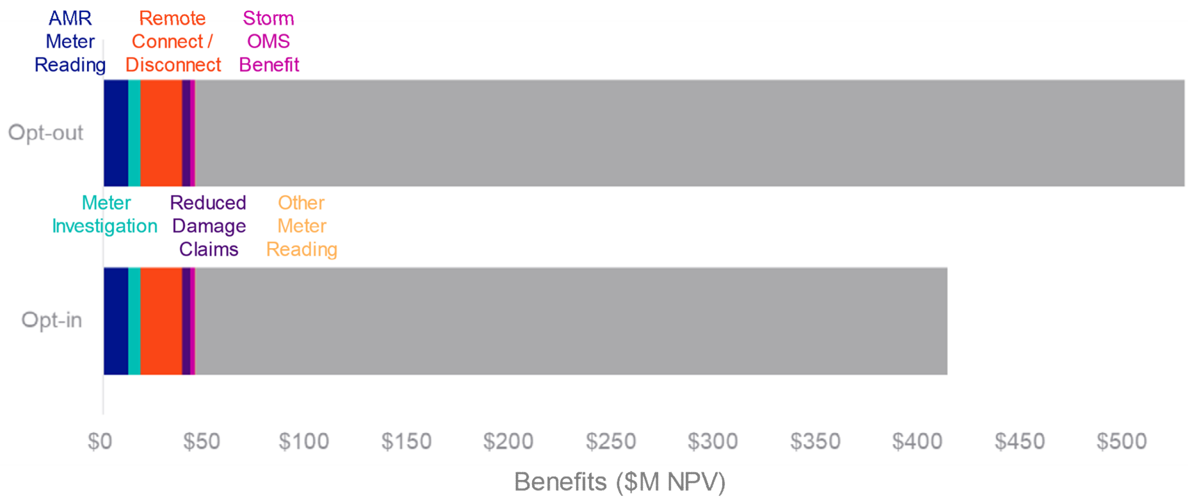


Figure 8-9: NPV benefits of the opt-out and opt-in cases with Avoided O&M Costs highlighted. Values shown represent the midpoint between high and low customer response cases.

Avoided AMR

The avoided AMR cost line item represents the avoided cost of replacing the aging AMR meters that are approaching the end of their estimated useful life. The benefit is primarily driven by the capital costs of the AMR meters including installation, as shown in Figure 8-10. This cost savings nearly offsets the capital and installation cost of the new AMF meters, but not the back-office systems and communications network required to operate the AMF system. The benefit highlights the advantages of aligning the proposed AMF deployment with the anticipated life-cycle replacement of AMR meters.

Should grid modernization efforts proceed in the absence of AMF, the need for granular usage data would exist but not be met by non-AMF meters. In such a case, the Company would have to deploy additional sensors throughout the distribution system to gather the data that would otherwise come from AMF meters. The Avoided Sensors benefit is the cost of the additional sensors that would be required in a non-AMF counterfactual scenario. While the Avoided AMR benefit is generally within the Company's control and therefore has a higher certainty, unlike the Avoided O&M benefit, Avoided AMR represents projected future costs (i.e., costs that are not incurred today) that will be avoided by AMF deployment.

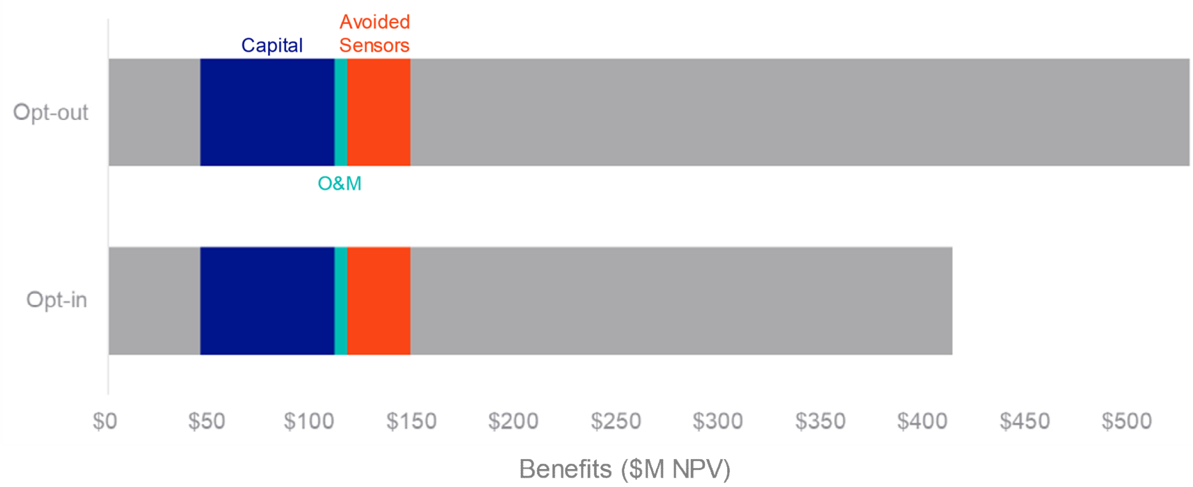


Figure 8-10: NPV benefits of the opt-out and opt-in cases with Avoided O&M Costs highlighted. Values shown represent the midpoint between high and low customer response cases.

Customer Benefits

AMF will provide customers with the enhanced understanding, choice, and control over their energy usage, enabling possible reductions in total bills. The quantified customer benefits from AMF-enabled savings include: 1) reduced energy loads from VVO; 2) customer response to energy insights/bill alerts; 3) avoided energy and demand cost associated with customers shifting EV charging from on-peak to off-peak periods; 4) shifting customer energy usage in response to TVR rates; and 5) reduced loss of customer load due to shorter duration outages.

Energy insights/bill alerts account for 13% to 17% of the total benefits. As described in the CEP (Attachment A), the savings are enabled by the CEMP. The increased visibility into energy usage afforded by the CEMP will enhance customers' ability to manage their energy consumption. Likewise, the Company will be able to assist customers through insights like personalized energy tips and mid-cycle bill predictions that will also be available on the CEMP.

Reductions in load drive additional benefits beyond the avoided energy and capacity costs. For example, reducing consumption and shifting usage to off-peak periods results in emissions reductions. Most of the emissions savings are counted under societal benefits, as they do not imply customer savings, but some benefit of CO_2 reduction is monetized through the Regional Greenhouse Gas Initiative (RGGI) and embedded in the avoided cost of electricity. The embedded CO_2 costs are included under customer benefits. The distinction between embedded and non-embedded emissions costs is discussed further in Section 8.5.

Also, any reduction in gas or electric energy and demand lowers the clearing price for all energy purchased via mechanisms referred to as Demand Reduction Induced Price Effect (DRIPE) and cross-DRIPE. This effect is also captured among the customer benefits, and it is discussed further in Section 8.5.

To the extent demand reductions occur during transmission and distribution peak hours, there are savings associated with deferral of related capacity cost. Given the increasing peaky-ness of load shapes in the absence of TVR, this effect is critical to avoiding overbuild of the distribution system. The GMP includes a complementary transmission and distribution investment deferral benefit attributable to other grid modernization measures not associated with TVR.

Though not quantified, AMF and grid modernization capabilities have option value compared to other grid investments. Traditional distribution infrastructure and energy storage are fixed in location and scale, whereas TVR can be designed and marketed to flexibly respond to where and how it is needed. More traditional infrastructure investments will still be required alongside AMF and grid modernization efforts, but the high-resolution data provided by AMF has the potential to make the investments more targeted and less risky.

The Company also includes a Customer Outage benefit, which quantifies the value to customers of reductions in lost load during outages. The benefit takes advantage of automated outage notification enabled by widespread AMF deployment.

Figure 8-11 highlights customer benefits among the total project benefits. The VVO and Energy Insights/Bill Alerts benefits do not require customers to be enrolled in TVR. However, other benefits, such as Non-EV Load Shifting, do depend on TVR enrollment. EV benefits from TVR are capped by TVR enrollment such that the number of EV owners receiving an incentive to shift charging away from peak hours does not exceed the number of residential customers enrolled in TVR. Because EV owners are likely to seek out low-cost charging, opt-in EV pricing benefits are conservative estimates.

Though the Company is not proposing adoption of the illustrative TVR design (i.e., TOU/CPP) as part of this filing, the Company believes that to realize the benefits described in the BCA, any proposed rate design must perform at least as well as the TOU/CPP rate used to perform the BCA. In short, the Company believes the illustrative TVR design should serve as a benchmark for the design of any future TVR proposal.

Outside of the VVO benefit, which is largely under the Company's control, customer benefits depend on customer behavior and regulatory decisions as much as the Company's actions. For this reason, the benefits are less within the Company's control and are therefore less certain.

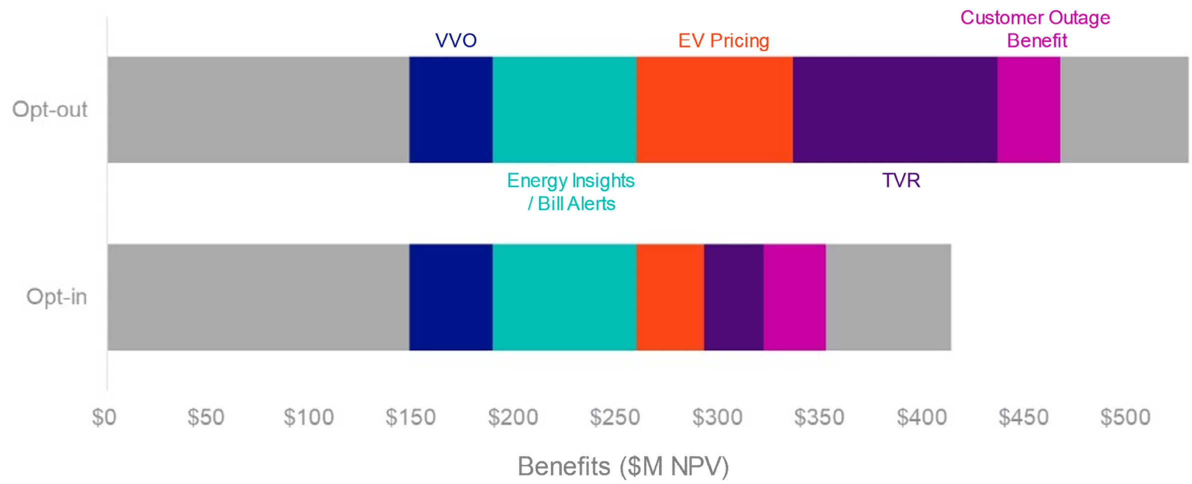


Figure 8-11: NPV benefits of the opt-out and opt-in cases with Avoided O&M Costs highlighted. Values shown represent the midpoint between high and low customer response cases

Societal Benefits

The customer benefits section referenced non-embedded emissions reductions benefits that do not directly impact customer costs, but that appear in the Rhode Island Test. The Company quantifies avoided economic damages due to climate risks such as coastal flooding and increased wildfire potential, as well as health-related benefits from reductions in CO_2, NOx and SOx. The reductions come in the form of CO_2 savings due to decreased truck rolls[111] and decreases in emissions from load shifting and energy conservation. Figure 8-12 shows these benefits as the last component of the total benefit stack. Societal benefits carry uncertainty with them for the same reasons as the customer benefits on which they depend. However, some benefits, such as avoided CO_2 from truck rolls and VVO-related benefits, are more within the Company's control.

[111] Decreased truck rolls include fewer vehicle trips to read meters, connect and disconnect service, and investigate service anomalies.

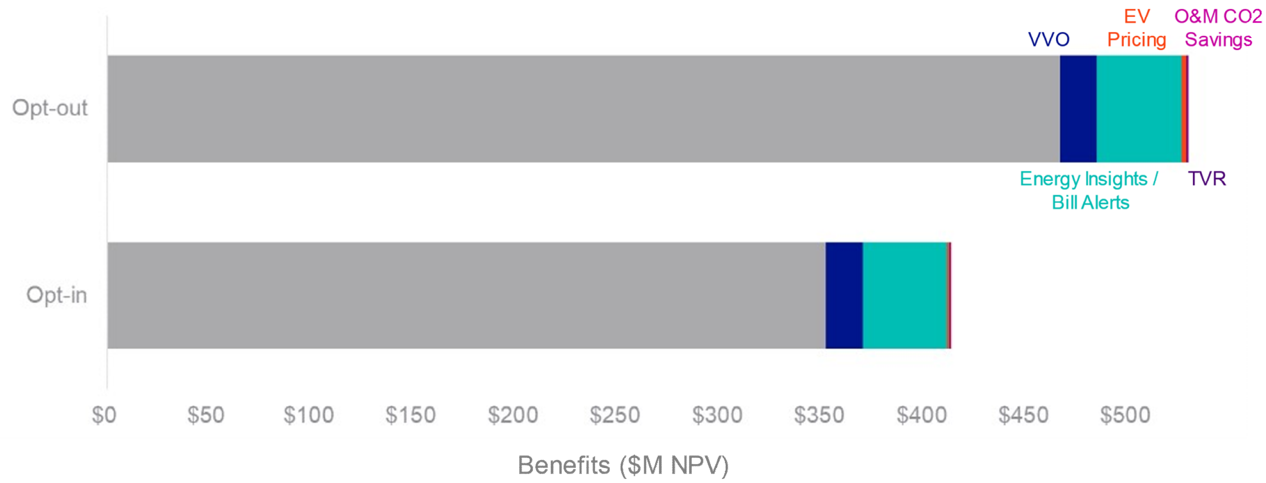


Figure 8-12: NPV benefits of the opt-out and opt-in cases with Avoided O&M Costs highlighted. Values shown represent the midpoint between high and low customer response cases

8.4.1. Benefits Realization

The Company has varying degrees of control over benefit realization. To address this uncertainty, benefits over which the Company has the least control have been expressed with bookended scenarios in the BCA (e.g., customer response). Figure 8-13 shows a breakdown of benefits (for the opt-out case) by the level of Company control associated with the benefit. A set of reporting metrics and potential PIMs to guide and support the achievement of benefits are discussed in Section 9 and in more detail in the Metrics and Performance Incentive Measures Roadmap (Attachment D).

Benefits can be classified as either delivered or enabled. Delivered benefits are those over which the Company has near-full control. This includes technology-enabled benefits like VVO as well as avoided cost benefit categories like Avoided AMR Costs, Avoided OMS Costs, and Non-OMS Avoided O&M Costs. Each of the benefits may be achieved through deployment of AMF, regardless of customer response. However, only the Non-OMS Avoided Costs impact the Company's bottom line. Whereas, VVO benefits, Avoided AMR Costs, and Avoided OMS Costs represent pass-through benefits and benefits over a counterfactual that do not impact the Company's bottom line and therefore do not impact the Company's revenue requirement.

Enabled benefits are those where the outcome is only partially controlled by the Company. Such benefits include customer benefits driven by TVR savings, energy insight/bill alert savings, and EV load shifting. The enabled benefits rely on a combination of customer awareness and willingness to act, as well as the Company's outreach and education efforts. The Societal

Benefits category includes non-monetized emissions cost savings, as well as RGGI savings that are tied to benefits that have larger uncertainty.

Based on this characterization, realization of 66% of expected benefits are only partially determined by the actions of the Company. Most of the enabled benefits rely on customer interaction with their energy consumption and response to price signals.

For completeness, the Company notes that avoided AMR benefits are more certain under the timeline presented in this Updated AMF Business Case. However, if significant delays in AMF approval and implementation push the deployment date out, it is possible that current AMR meter assets would require replacement prior to AMF meter rollout. This would weaken the delivered benefits number reported here by introducing additional stranded assets.

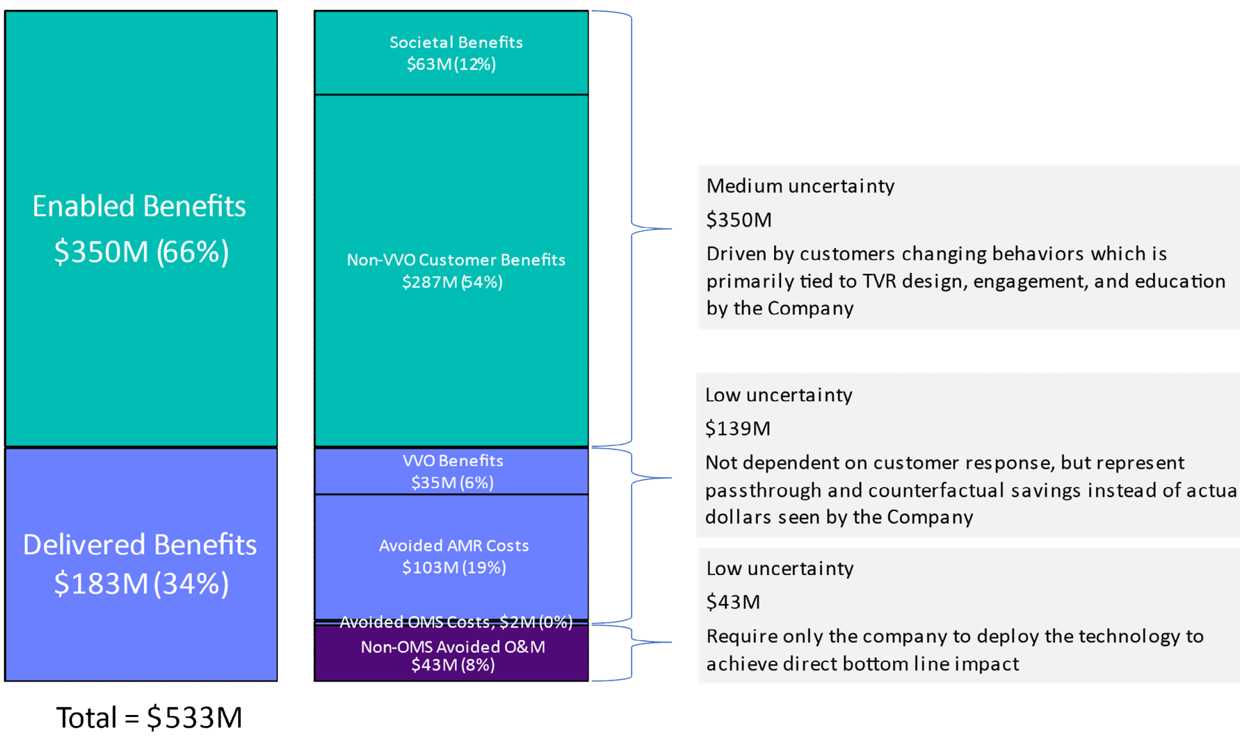


Figure 8-13: Benefit amounts (20-year NPV, Opt-out case) grouped by Uncertainty as determined by Company's ability to control benefit realization

The benefits discussed earlier align to the enabled and delivered benefits shown in Figure 8-12 as follows:

Table 8-7: Crosswalk between Figure 8-12 benefit categories and benefit categories identified in Section 8.4

Figure 8-12 Benefit Category	Section 8.4 Benefit Category
Societal Benefits	Societal Benefits (Enabled Benefit)
Non-VVO Customer Benefits	Customer Benefits (Enabled Benefit)
VVO Benefits	Customer Benefits (Delivered Benefit)
Avoided AMR Costs	Avoided AMR Replacement Costs (Delivered Benefit)
Avoided OMS Costs	Avoided O&M Costs (Delivered Benefit)
Non-OMS Avoided O&M	Avoided O&M Costs (Delivered Benefit – Rev. Req. Impact)

The Company proposes to provide 80% of the Non-OMS Avoided O&M Cost benefit to customers through an upfront adjustment to the revenue requirement in the first rate period following AMF approval to account for these savings. This commitment provides a strong incentive for the Company to deliver the Non-OMS Avoided O&M benefits, as there is a financial risk for failing to deliver them in a timely manner (i.e., if the benefits are not realized coincident with how they are included in the revenue requirement, the Company will collect less money than the costs it is incurring). Traditionally, such operational savings would not be reflected until they are captured in the historic test year and incorporated in base rates set during the next rate proceeding. With this approach, however, customers are guaranteed cost savings sooner. This commitment is discussed further in Attachment D: Metrics and Performance Incentive Measures Roadmap.

For enabled benefits tied to customer behavior, the Company evaluated a range of customer response and participation assumptions to determine the level of responsiveness necessary for the AMF program to be cost effective. As shown in Appendix 10.4, the Company found the program is likely cost effective even without any customer-driven benefits (e.g., TVR and Energy Insight/Bill Alerts) in a scenario that assumes high DER adoption. Adding in customer-driven benefits would increase benefits by $292 million (opt-out) / $175 million (opt-in), resulting in net program benefits of $309 million (opt-out) / $198 million (opt-in).

Although customer responsiveness is not wholly within the Company's control, there are opportunities for the Company to influence customer behavior and therefore the extent of program cost-effectiveness. For example, evidence from recent pilots suggests that marketing and customer education helps consumers best utilize new rate designs like TVR.[112] The Company remains committed to making TVR, energy insights, and bill alerts available to customers regardless of the extent to which these benefits are needed to achieve cost-effectiveness. Additionally, the Company's analysis reveals that changes in TVR participation have a mild effect on the BCA ratio. This finding bolsters the program's ability to deliver benefits despite uncertainty around the number of customers that may migrate to third-party supply service.

The Company also evaluated the resilience of the BCA ratios to changes in the meter opt-out rate – testing the impact of larger numbers of customers choosing not to install an AMF meter. Even assuming unprecedented levels of meter opt-out,[113] the Company found the program is unlikely to see a material impact to the BCA ratios. For example, increasing the meter opt-out rate from 1% to 10% drops the BCA ratio for opt-out TVR from 2.38 to 2.32.

8.5. Comparison of Costs and Benefits to Docket No. 4780 PST Plan Filing

To provide context around the results of the BCA and to show the thorough approach consistent with the Docket 4600 Framework, this section compares the results of the 2017 AMF BCA presented in Docket No. 4780 with the BCA supporting this Updated AMF Business Case. Above Figure 8-3 is a waterfall chart comparing previous BCA results to current BCA results for opt-out TVR enrollment. Below, Figure 8-14 shows a similar waterfall chart for the opt-in case. For the opt-in case shown here, the new categories provide approximately $122 million in benefits.

[112] *See* Lupe R. Jimenez, Jennifer M. Potter, and Stephen S. George, *SmartPricing Options Interim Evaluation: An interim evaluation of the pilot design, implementation, and evaluation of the Sacramento Municipal Utility District's Consumer Behavior Study* (2013); *see also* Xcel Energy, Residential Time of Use Rate Design Pilot Program, Docket No. E002/M-17-775 (2017).

[113] The Company further assumed that it would still be able to deploy a mesh network technology solution under the illustrative 10% meter opt-out scenario.

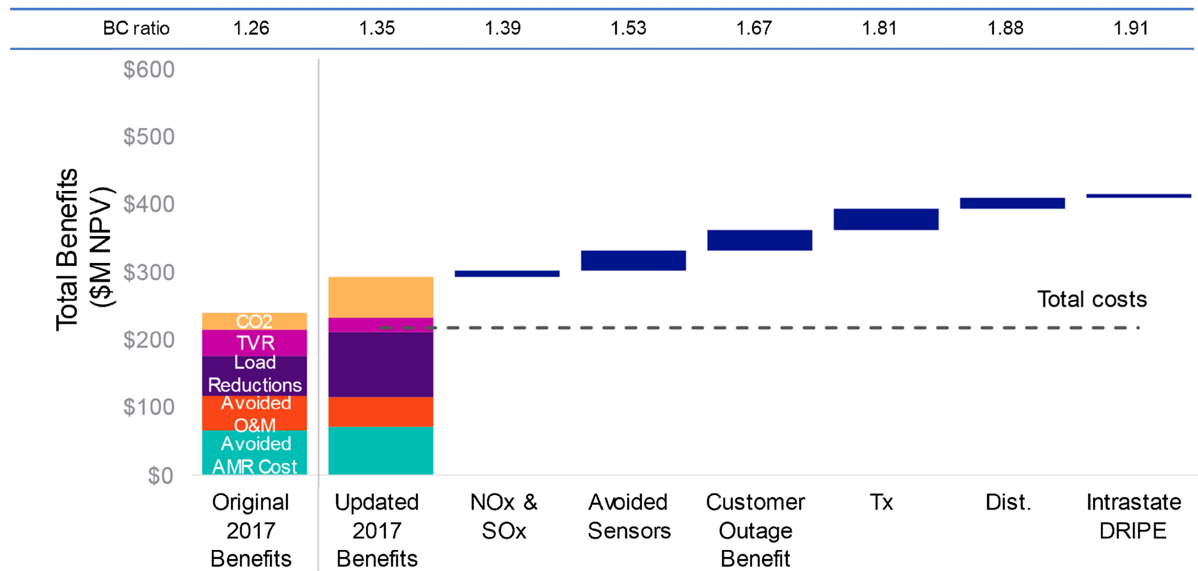


Figure 8-14: <u>Opt-in</u> benefits broken out by category. Categories in the stacked bars are categories that were included in the 2017 BCA. Categories in the waterfall are new to the BCA in this filing.

For the sake of isolating and illustrating the impacts of certain benefit categories relative to the 2017 filing, the Company slightly disaggregated the customer and societal benefit categories presented in Section 8.4 and Appendix 10.5 as follows:

- <u>Benefits included in Docket No. 4780 filing</u>:
  - *Load Reductions* includes VVO, Energy Insights/Bill Alerts, as well as load disaggregation benefits. The load reductions benefit has increased from the original business case filed in Docket 4780 due to a combination of updated spot market prices and revisiting the energy insights assumptions as a part of the Company's New York affiliate's 2018 AMI filing.
  - *TVR* includes benefits from shifting both EV and non-EV loads. The TVR methodology employed by the model has become more sophisticated since 2017, and a survey of TOU elasticities discussed in Appendix 10.4 provides updated assumptions on customer response to price signals.
  - *CO_2* includes embedded and non-embedded costs of CO_2. This benefit has grown in accordance with high CO_2 price forecasts and the above-mentioned increase in load reductions.

- New benefits per Docket 4600 Framework:

  - *NOx & SOx* includes emissions benefits due to load reductions and TVR. This corresponds to "Criteria Air Pollutant and Other Environmental Externality Costs" and "Public Health" in the Docket 4600 Framework.

  - *Avoided Sensors* includes the avoided cost of additional feeder monitoring sensors that would be need in the absence of widespread AMF deployment. This corresponds to "Distribution Delivery Costs" in the Docket 4600 Framework.

  - *Customer Outage Benefit* includes economic benefits to customers based on improved outage response times as determined using the Lawrence Berkeley National Laboratory's Interruption Cost Estimate (ICE) model. This corresponds to "Distribution System and Customer Reliability/Resilience Impacts" in the Docket 4600 Framework.

  - *Tx* includes deferred transmission savings due to both load reductions and TVR. This corresponds to "Electric Transmission Capacity Value" in the Docket 4600 Framework.

  - *Dist.* includes deferred distribution savings due to both load reductions and TVR. This corresponds to "Distribution Capacity Costs" in the Docket 4600 Framework.

  - *Intrastate DRIPE* includes electric DRIPE, gas DRIPE, and cross-DRIPE effects due to both load reductions and TVR. The DRIPE category is split into Intrastate and Rest of Pool (ROP) components. Only the intrastate component, which considers savings to Rhode Island customers, is included to align with industry best practices of BCAs for AMF. This corresponds to "Demand Reduction Induced Price Effect (DRIPE)" in the Docket 4600 Framework.

The Company notes that careful consideration of Docket 4600 has added more than the three categories listed above. This section refers to the most impactful new components, but the Company has added others of lesser magnitude to the updated BCA as well. Appendix 10.5 provides a full list of the categories listed in the Docket 4600 Framework and the Company's consideration of each in the context of this Updated AMF Business Case.

8.6. Alternative BCA formulations

During the stakeholder engagement process, stakeholders identified alternatives to the BCA formulation proposed by the Company. To show how the alternative BCA formulations affect program cost-effectiveness, this section presents BCA results based on the following alterations to the BCA:

- Inclusion of the economic development impacts of AMF;
- Use of forecasts that follow a low DER adoption trajectory and do not meet policy goals;
- Inclusion of revenue benefits of AMF;
- Inclusion of ROP DRIPE effects from AMF; and
- Use of a lower societal discount rate instead of after-tax WACC.

Figure 8-15 provides the range of BCA ratios achieved by each sensitivity. The Company notes that only the low DER adoption sensitivity produces a ratio smaller than that of the Base Case – this is due mainly to a smaller amount of electrified load in the scenario. All sensitivities maintain high enough benefits, even at the low end, to remain cost effective.

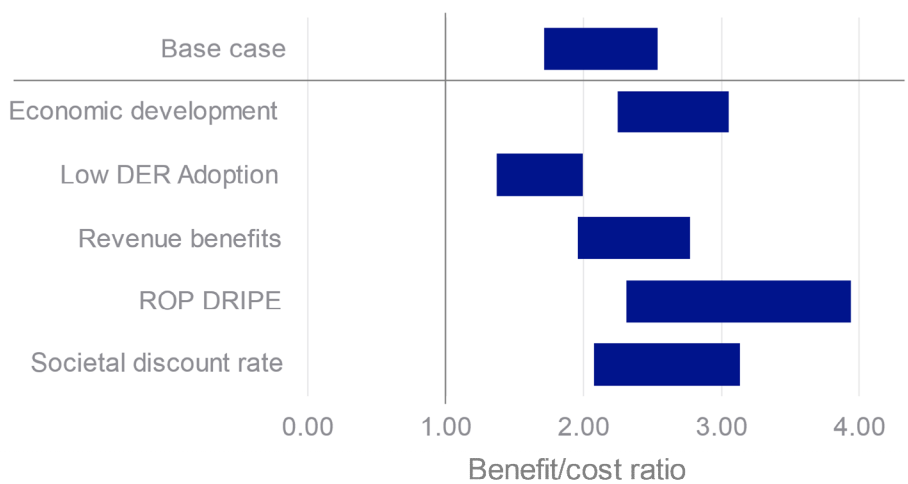


Figure 8-15: The full range of BC ratios for all sensitivities. Minimum values correspond to the Opt-in Low benefits case. Maximum values correspond to the Opt-out High benefits case

Table 8-8 provides the actual cost and benefit increases and decreases for each sensitivity relative to the Base BCA. The Company notes that, while some of the sensitivities could be combined in an “ala carte” manner to surmise combined effects (revenue benefits, ROP DRIPE, economic development), the effects of the societal discount rate and low DER adoption scenario are more complex and cannot be combined with other sensitivities without additional extensive analysis.

Table 8-8: Impact of sensitivities on BCA results.
Cost and benefit amounts are given on a 20-year NPV basis.

	Opt-out			Opt-in		
Sensitivity	**Effect on costs (M$)**	**Effect on benefits (M$)**	**BCA ratio**	**Effect on costs (M$)**	**Effect on benefits (M$)**	**BCA ratio**
Economic development	-	+$115.86	2.90	-	+$115.86	2.44
Low DER adoption	-	-$119.51	1.85	-	-$74.55	1.57
Revenue benefits	-	+$53.35	2.62	-	+$53.35	2.16
ROP DRIPE	-	+$333.75	3.87	-	+$132.79	2.52
Societal discount rate	+$56.52	+$291.23	2.94	+$52.08	+$209.95	2.32

8.6.1. Economic Development

The Docket 4600 Framework includes economic development benefits, providing that such benefits can either be reflected via a qualitative assessment or quantified through detailed economic modelling. The Company and PST Advisory Group stakeholders agree that economic development benefits are important. However, stakeholders also agree that including the economic development benefits in the Base Case BCA is difficult. In Appendix 10.5.2, the Company explains the reasons why the quantified economic development benefits are difficult to include and discusses the method for developing this sensitivity.

The Company estimated economic impacts using the Regional Economic Models, Inc. (REMI) regional economic model of the Rhode Island economy, as shown in Figure 8-16. The overall societal impact is measured by net gross domestic product (GDP), which encompasses job years, incomes, state tax revenues and the increased competitiveness of Rhode Island business firms. This has a 20-year NPV of $115.86 million and can be considered alongside other AMF benefits in the BCA.

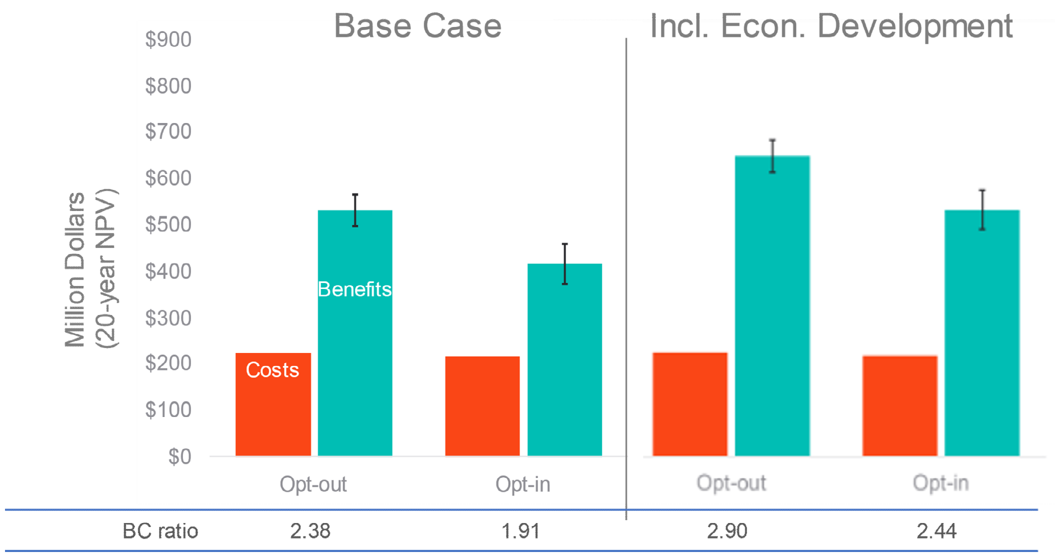
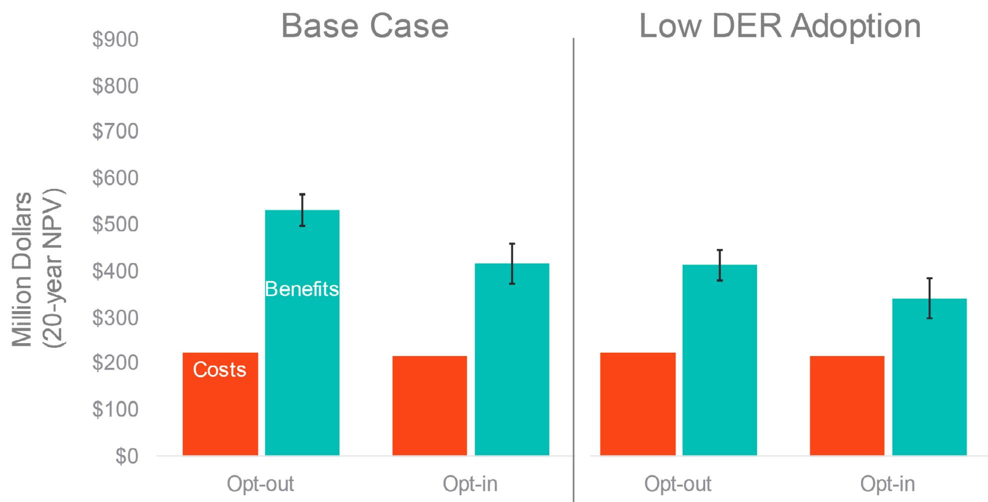


Figure 8-16: NPV costs and benefits of opt-out and opt-in scenarios comparing economic development benefits. Upper and lower bounds of benefits defined by high and low customer response cases (bar corresponds to midpoint).

8.6.2. Low DER Adoption Scenario

While the Company's Base Case BCA focuses on a future that achieves 40% reduction in GHG emissions by 2030, there is a possibility that the targets are not met. To understand the implications of this hypothetical future, the Company analyzed a low DER adoption scenario that does not achieve state policy ambitions. The scenario assumes lower adoption levels of heat pumps, EVs, and distributed generation. As a result, the Company would expect decreases in the benefits related to the adoption levels of each technology (e.g., reductions in EV and non-EV load shifting and VVO). Despite the decrease in benefits in a low DER adoption scenario, the program remains cost effective in all cases, as shown in Figure 8-17.



BC ratio	2.38	1.91	1.85	1.57

Figure 8-17: NPV costs and benefits of opt-out and opt-in for the Low DER Adoption scenario. Upper and lower bounds of benefits defined by high and low customer response cases (bar corresponds to midpoint).

8.6.3. Revenue Benefits

Revenue benefits include three sub-categories: improvement over electromechanical meter accuracy, reduction in theft of service, and reduction in bad debt write-offs. As these all lead to the Company either over- or under-collecting, which is then corrected in rates, these categories are regarded as transfers between ratepayers. As such, they would not appear in the Rhode Island Test. Nevertheless, reducing unintentional transfers between ratepayers is a positive outcome that the Company and stakeholders wish to highlight as an additional benefit of AMF that does not appear in the BCA.

Stakeholders have expressed interest in seeing the revenue benefits quantified in the BCA supporting this Updated AMF Business Case. The combined effect of these considerations increases the benefits by $53.35 million regardless of the customer response, co-deployment, or TVR enrollment cases. Figure 8-18 shows the results of this sensitivity analysis. Though the Company does not include this component in the Base Case BCA, inclusion would only increase the BCA ratio.

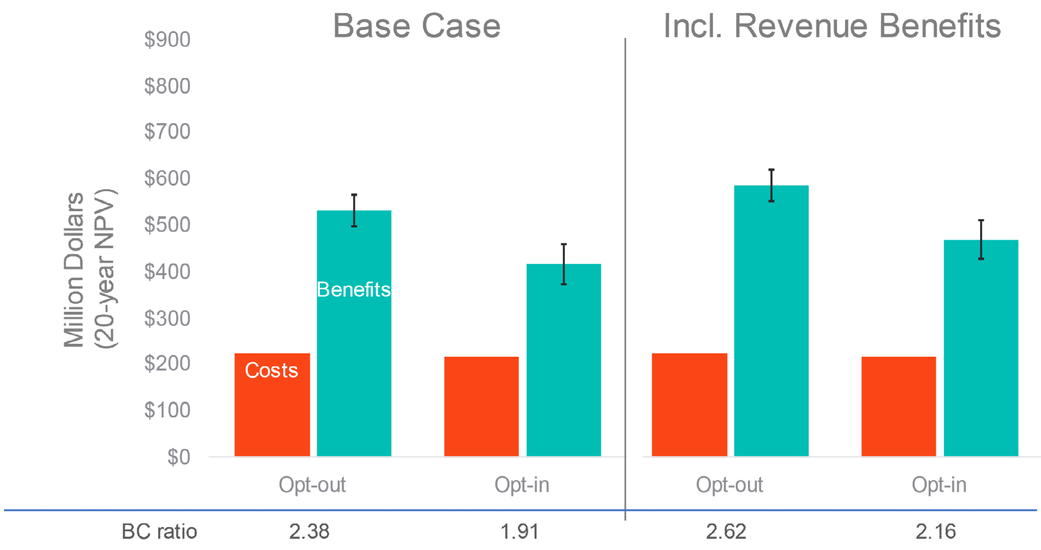


Figure 8-18: NPV costs and benefits of opt-out and opt-in scenarios comparing revenue benefits. Upper and lower bounds of benefits defined by high and low customer response cases (bar corresponds to midpoint).

8.6.4. <u>ROP DRIPE</u>

While the base case BCA includes only intrastate DRIPE, stakeholders expressed an interest in seeing results that include the ROP portion of DRIPE as well. The results using ROP DRIPE appear in Figure 8-19. As the DRIPE impact is tied to customer response, this change affects the opt-out case (benefits increase by $334 million) more than the opt-in case (benefits increase by $133 million). Though the Company does not include this component in the Base Case BCA, the inclusion would only increase the BCA ratio.

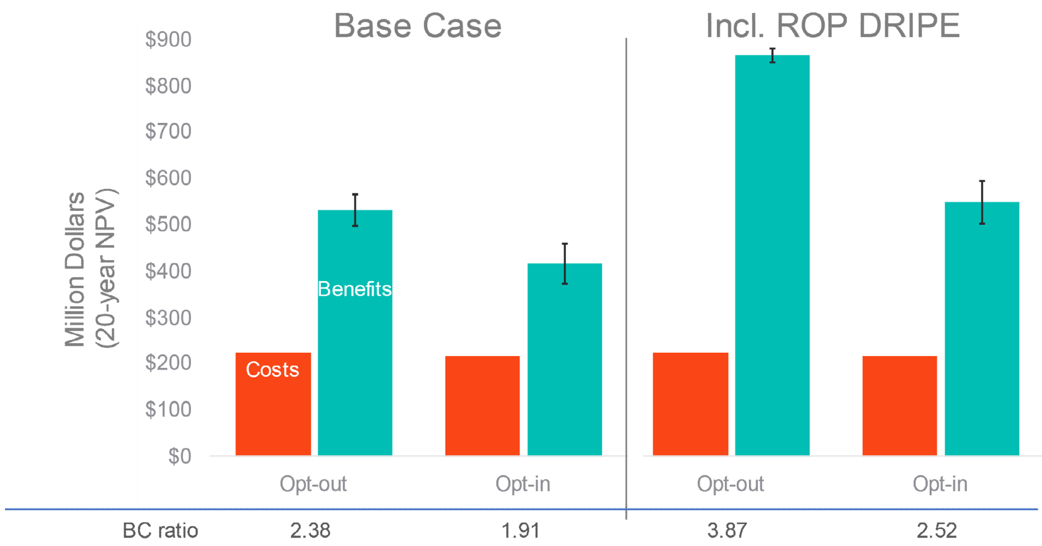


Figure 8-19: NPV costs and benefits of opt-out and opt-in scenarios comparing ROP DRIPE benefits. Upper and lower bounds of benefits defined by high and low customer response cases (bar corresponds to midpoint).

8.6.5. Societal Discount Rate

The Company maintains that the most reasonable rate at which to discount future year costs and benefits is the after-tax WACC. However, stakeholders requested to see results given a lower societal discount rate. Using a discount rate of 3% values cash flows in later years more than they would be valued using a higher discount rate. This means that both costs and benefits increase with this sensitivity.

Since most costs occur in early years, but benefits occur in later years, the net effect is that the BCA ratios improve to 2.94 and 2.32 for opt-out and opt-in scenarios, respectively. The results of this sensitivity appear in Figure 8-20. Though the Company does not use this discount rate in the Base Case BCA, the inclusion would only increase the BCA ratio.

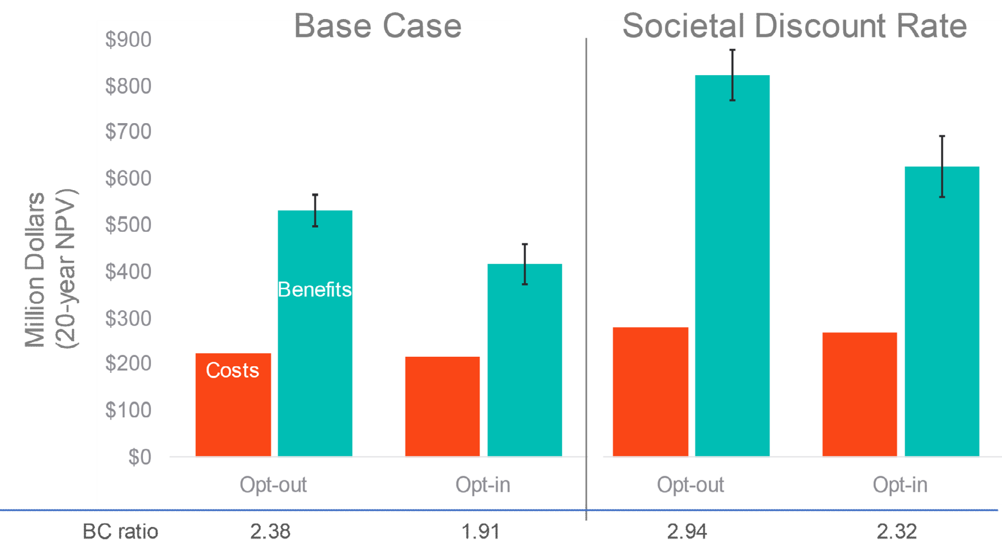


Figure 8-20: NPV costs and benefits of opt-out and opt-in cases compared to a scenario that uses a 3% societal discount rate. Upper and lower bounds of benefits defined by high and low customer response cases (bar corresponds to midpoint).

9. Reporting and Risk Management

As referenced throughout Section 8, realization of benefits is essential to Rhode Island ratepayers. The success of achieving benefits can be bolstered through effective program reporting and risk management. This section describes the Company's approach to reporting and risk management.

9.1. Reporting

For the purposes of tracking and reporting AMF implementation costs, the Company will generally follow the approach it currently uses for large projects. On a semi-annual fiscal-year basis the Company will file an AMF program report with the PUC. The AMF program report will address the status of the AMF deployment, including: 1) a narrative explaining overall AMF implementation status; 2) detail on actual spending relative to the AMF budget; 3) identify allocations of AMF costs to the Company as appropriate; and 4) include explanations of variances between budgets and actual spending. Additionally, once a year, in the AMF program report filed sixty days after the end of each respective fiscal year, the Company will include: 1) any cost or timeline differences that exceed 10% for the fiscal year; and 2) the latest AMF sanction paper authorized during the fiscal year. The Company will also hold semi-annual meetings with the Division and OER to review the AMF program report.

9.2. Risk Management

The scale, scope, and term of the AMF proposal requires careful risk management to provide reasonable assurance that customers will realize the envisioned benefits of the program. The Company believes it has taken the necessary steps in developing the AMF proposal and deployment plan to manage the risk under its direct control while also explicitly recognizing certain risks that are beyond its control. The Company's comprehensive approach to risk management is described in detail in other sections of the business case and summarized below:

Solution Management:

- The AMF proposal was developed and evaluated in concert with the broader GMP where a long-term integrated GMP and AMF roadmap was developed and evaluated on a benefit-cost basis to ensure the timing and associated costs of new functionalities are aligned with system and customer needs. The evaluation resulted in the development of a five-year plan in core, enabling functionalities, including AMF, that are common to all future-state scenarios evaluated.[114]

- Alternative metering solutions were identified and compared to AMF within this business case in terms of their relative functionalities, benefits, and costs. The results demonstrate that full deployment of AMF is the most cost-effective approach and it provides the most robust set of functionalities to support evolving customer expectations.[115]

- The procurement process for the AMF solution evaluated functionalities, vendor roadmaps, and solution offerings such as SaaS, to provide solution flexibility and adaptability to address the risk of technology obsolescence.[116]

Managing Cost Risk and Delivering Benefits:

- Multiple actions have been taken regarding AMF program cost estimates to establish enhanced cost certainty as compared to the Company's prior filing estimates. Primary to these efforts is cost estimate refinement through the RFS solicitation for the major components of the AMF solution including the electric meters, gas modules, FAN equipment, back-office systems, and related professional services. The costs of periodic technology refreshes (hardware and software) over the 20-year term of the BCA and non-RFS component cost contingencies have also been factored into the costs. Lastly, the

[114] *See* Section 4 for additional details.

[115] *See* Section 5.1 for details.

[116] *See* Sections 5.2 and 5.3 for additional details.

Company has leveraged its experience with past large-scale meter deployments and industry references to refine the cost and benefit categories.[117]

- The Company developed a comprehensive CEP with input from stakeholders to support the achievement of the envisioned customer benefits. The plan includes a three-phased approach to customer engagement: 1) pre-deployment customer AMF awareness; 2) a 90-60-30-day plan for engaging customers during meter deployment; and 3) customer empowerment and enablement after the meter is installed.[118]

- Maximizing the value of AMF requires integration with existing programs and commitment to ongoing utilization of the AMF system to enable new functionalities.[119]

- The Company conducted a comprehensive BCA consistent with Docket 4600 Framework, evaluating alternative deployment scenarios and key cost and benefit sensitivities.[120]

- To measure the progress and effectiveness of the Company's planned AMF deployment, the Company has developed a proposed Metrics and PIMs Roadmap that includes a robust set of initial metrics that it proposes to report on a semi-annual and annual basis and a process timeline for the development of performance incentives that promote program efficiency and effectiveness.[121]

- The Company has developed a robust project governance structure to support effective implementation.[122]

[117] *See* Section 8.2.
[118] Attachment A.
[119] *See* Sections 5.3.3 and 7.5.
[120] *See* Section 8.
[121] Attachment D.
[122] *See* Section 7.3.1.

10. Appendix

10.1. Acronym List

aaS = As a Service
ADMS = Advanced Data Management System
AMF = Advanced Meter Functionality
AMI = Advanced Meter Infrastructure
AMIaaS = AMI as a Service
AMP = Arrears Management Plan
AMR = Automated Meter Reading
ANSI = American National Standards Institute
API = Application Programming Interface
ASA = Amended Settlement Agreement
BAN = Business Area Network
BAU = Business as Usual
BCA = Benefit Cost Analysis
BE = Beneficial Electrification
BMS = Business Management System
BYOT = Bring Your Own Technology
C&I = Commercial and Industrial
CCA = Community Choice Aggregator
CCST = California Council on Science and Technology
CEMP = Customer Energy Management Platform
CEP = Customer Engagement Plan
CGR = Connected Grid Router
CIS = Customer Information System
CO_2 = Carbon Dioxide
COEs = Centers of Excellence
CPP = Critical Peak Pricing
CPR = Critical Peak Rebate
CSS = Customer Service System
CVR = Conservation Voltage Reduction
D/Dist = Distribution
DCFC = Direct Current Fast Charging
DER = Distributed Energy Resource
DERMS = Distributed Energy Resource Management System
DG = Distributed Generation
DLM = Dynamic Load Management
DPAM = Distribution Planning & Asset Management
DOE = Department of Energy
DP&L = Dayton Power and Light
MA DPU = Massachusetts Department of Public Utilities
DR = Demand Response
DRIPE = Demand Reduction Induced Price Effect
DSCADA = Distributed Supervisory Control and Data Acquisition
DSIP = Distributed System Implementation Plan
DSP = Distributed System Platform
EC4 = Executive Climate Change Coordinating Council
EDI = Electronic Data Interchange
EE = Energy Efficiency
EHP = Electric Heat Pump
EIA = Energy Information Administration
EM&V = Evaluation, Measurement, and Verification
EPO = Energy Profiler Online
EPRI = Electric Power Research Institute
ERT = Encoder Receiver Transmitter
ESB = Enterprise Service Bus
EV = Electric Vehicle
FAN = Field Area Network
FCC = Federal Communications Commission
FCS = Field Collection System
FLISR = Fault Location Isolation and Service Restoration
FTE = Full-time Employee
GBC = Green Button Connect
GBD = Green Button Download My Data

GDP = Gross Domestic Product
GDPR = General Data Protection Regulation
GHG = Greenhouse Gas
GIS = Geographical Information Systems
GMP = Grid Modernization Plan
HAN = Home Area Network
HCA = Hosting Capacity Analysis
HECO = Hawaiian Electric Company
HES = Head-End System
HVAC = Heating, Ventilation, and Air Conditioning
ICAP = Installed Capacity
ICE = Interruption Cost Estimate
IEI = Institute of Electric Innovation
IoT = Internet of Things
IOUs = Investor Owned Utilities
ISA = Interconnection Service Agreement
ISR = Infrastructure, Safety, and Reliability
IT = Information Technology
kW = Kilowatt
kWh = Kilowatt hour
LDV = Light Duty Vehicle
LED = Light Emitting Diode
LIHEAP = Low-Income Home Energy Assistance
LVA = Locational Value Analysis
MA = Massachusetts
MaaS = Meters as a Service
MDMS = Meter Data Management System
MRP = Multi-Year Rate Plan
MV/LV = Medium Voltage/Low Voltage
NaaS = Network as a Service
NG = National Grid
NMPC = Niagara Mohawk Power Corporation
NOx = Nitrogen Oxide
NPP = Non-Regulated Power Producer
NPV = Net Present Value
NY = New York
NYPSC = New York Public Service Commission
NWA = Non-Wires Alternative
OER = Office of Energy Resources
O&M = Operations and Maintenance
OMS = Outage Management System
ORU = Orange and Rockland
PBR = Performance-Based Regulation
PI Historian = Plant Information Historian
PII = Personal Identifiable Information
PIM = Performance Incentive Mechanism
PLC = Power-Line Communication
PMO = Project Management Office
PSE&G = Public Service Electric & Gas
PSR = Platform Service Revenue
PST = Power Sector Transformation
PUC = Public Utilities Commission
PV = Photovoltaic
REC = Renewable Energy Credit
REG = Renewable Energy Growth
REMI = Regional Economic Models, Inc
REV = Reforming the Energy Vision
RF = Radio Frequencies
RFI = Request for Information
RFS = Request for Solution
RFP = Request for Proposal
RGGI = Regional Greenhouse Gas Initiative
RI = Rhode Island
RMD = Residential Methane Detector
RTP = Real Time Pricing
RTU = Remote Terminal Unit
SaaS = Software as a Service
SCADA = Supervisory Control and Data Acquisition
SCE = Southern California Edison
SCT = Societal Cost Test
SECC = Smart Energy Consumer Collaborative
SMB = Small-Medium Business
SME = Subject Matter Expert
SMUD = Sacramento Municipal Utility District
SOx = Sulphur Oxide
SWSN = State-Wide Shared Network

ToC = Table of Contents
TOU = Time Of Use
TVR = Time Varying Rate
TX = Transmission
VAR = Volt Ampere Reactive
VDER = Value of Distributed Energy Resources
VEE = Validation, Estimation, and Editing
VMT = Vehicle Miles Traveled
VPP = Variable Peak Pricing
VVO = Volt-VAR Optimization
WACC = Weighted Average Cost of Capital
WAN = Wide Area Network

10.2. Screening Analysis of Targeted AMF Deployment

To assess the cost effectiveness of a targeted AMF deployment, the Company considered how a targeted roll out would affect the assumptions made in the full-scale deployment AMF BCA model. The assumptions, shown in Table 10-1, were adjusted in the BCA model to create a screening analysis of targeted AMF deployment.

Table 10-1: Parameters considered in the analysis of targeted AMF deployment

Category	Parameter considerations
System	Meter population at 20% of total to align with expected TOU/CPP opt-in participation rate
Benefits	All benefits related to avoided AMR reduced by 80% as AMR meters will be installed in the absence of full-scale AMI
	Remote metering/disconnect benefits reduced to 20% to match meter population with AMF
	No avoided AMR meter reading related benefits can be taken as there will be no reduction in AMR labor or equipment
	TOU/CPP benefits are only applicable to opt-in scenarios
	OMS Operational Benefit Removed – No benefit without full-scale AMF implementation
	OMS Societal Benefit reduced to 20% to align with AMF participation rate
	VVO integration benefits reduced to 20% to align with AMF participation rate
	Energy Insights related benefits reduced to 20% to align with AMF participation rate
	Associated CO_2 benefits reduced as well
Costs	Metering costs only inclusive of 20% cellular meter population
	All FAN related costs removed from calculations
	Increased cost for meter LTE communications
	Reduced all PMO, Call Center, AMO and Professional Services cost by 50% to account for smaller program rollout
	Field facility and related management/coordination costs reduced by 50%
	IT Telecom costs reduced by 50%
	IT Data Lake costs reduced by 50%
	Customer Engagement costs reduced to account for meter population
	IT/Cyber CapEx, OpEx and run-the-business (RTB) costs adjusted to account for smaller footprint, but includes static stand-up costs

This scenario results in a significant benefit reduction, with only a modest cost reduction. This is due, in part, to the higher cost of cellular meters, which are required in a targeted deployment.[123] This generates a significant cost burden for the targeted deployment scenario. Additionally, without the avoided AMR benefit, not only does the AMF BCA see reduced benefits, the Company would incur significant stranded asset costs if it were to implement full-scale AMF deployment in the future.

Moreover, significant IT investment is required, even with targeted AMF deployment, to achieve the projected benefits outlined in this Updated AMF Business Case. As a portion of the IT costs do not scale with meter volume (i.e., the extensive cost will be incurred regardless of the size of the meter deployment). For both the high- and low-realization scenarios the BCA ratios are below 1.00.

Though the screening analysis supporting the results is less robust than the BCA used to develop the full AMF deployment costs and benefits, the vast gap between costs and benefits, even in the best targeted-deployment scenario, indicates that such an approach would result in a net cost to the state. The Company, therefore, determined that full-scale AMF deployment is the most cost-effective fit-for-purpose approach.

[123] *See* Section 6.5.

10.3. Data Latency Benchmarking

The tables below present the results of a survey performed by National Grid of smart meter data latency across North America.

Table 10-2: Data latency industry comparison - Electric

Utility	Read Interval	Frequency of Upload to Head End System	Delay in Data Posted	Type of Data Posted (Raw vs. Validated)
Entergy	15 min for Res (90%) 5 min for C&I (10%)	6x day	Next day	Validated
OG&E	15 min	Res (4x day) Portal (24x day) Demand Response (96x day)	Everyone else (Daily) Portal Customers (1 hour) Demand Response (15 mins)	Raw data is posted, then 24 hours later it is updated after validation
ppl	15 min	6x day	Next day	Validated
Xcel Energy	15 min	6x day	Next day	Validated
Hydro Québec	15 min for Res (90%) 5 min for C&I (10%)	6x day	Next day	Validated
ComEd. An Exelon Company	30 min	6x day	Next day	Validated
Duke Energy	30 min (90%) / 15 min (10%) based on jurisdiction	1x day	Next day	Validated
WestPenn Power, Penelec, PennPower, Met-Ed	60 min for Res (90%) 15 min for C&I (10%)	1x day	Next day	Validated
hydro one	60 min	2x day	Next day	Validated
Oncor	60 min for Res 30 min for C&I	Ongoing	Next day	Validated
PECO. An Exelon Company	60 min for register-billed accounts; 15 min for interval-billed accounts	6x day	Next day	Validated
Vectren Live Smart	60 min (93%) / 5 min (7%); Electric MV90 - 5 min	3x day	N/A - Not presented at this time	NA

Table 10-3: Data latency industry comparison - Gas

Utility	Read Interval	Frequency of Upload to Head End System	Delay in Data Posted	Type of Data Posted (Raw vs. Validated)
Entergy	60 min	2x day	Next day	Validated
PECO. An Exelon Company	60 min	6x day	Next day	Validated
Vectren Live Smart	60 min	3x day	N/A - Not presented at this time	NA

10.4. TVR Details

10.4.1. Customer Response Elasticities

National Grid conducted a survey of customer elasticities in response to TVR to understand how customer usage can be expected to change given a TOU price signal. Table 10-4 shows the results of this survey. Noting that Rhode Island is a summer-peaking region, the Company uses elasticity ranges of -0.06 to -0.10 for opt-out TVR enrolment and -0.10 to -0.18 for opt-in TVR enrolment. Based on the Company's load profile and the peak periods described in Section 8.2.1, these yield the on-peak energy reductions, off-peak energy increases, and peak demand reductions used in the BCA.

Table 10-4: Survey of substitution elasticity estimates

Study	Utility or Jurisdiction	Description	Season or customer type	Peak/Off-peak Price Ratio	Length of Peak Period	Substitution Elasticity Estimate
CRA, 2005[124]	California Statewide Pricing Pilot	Residential pilot with three rates: TOU, TOU-CPP, and TOU-VPP ("CPP-V"); estimate here is for the TOU-CPP rate (statewide, summer 2003 and 2004)*	Summer	CPP: 6.5 TOU: 2.4	5 hours	-0.08
Faruqui et al., 2016[125]	Ontario, Canada	Province-wide default TOU pricing for residential customers;	Summer peak	~1.5 (since 2015 ~2)	6 hours	-0.08
			Winter morning peak	N/A	4 hours	-0.02

[124] Charles Rivers Associates (CRA), *Impact Evaluation of the California Statewide Pricing Pilot* (2005).

[125] *See* Faruqui, A., Lessem, N., Sergici, S., Mountain, D., Denton, F., Spencer, B., King, C., *Analysis of Ontario's Full Scale Roll-out of TOU Rates – Final Study* (2016).

Study	Utility or Jurisdiction	Description	Season or customer type	Peak/Off-peak Price Ratio	Length of Peak Period	Substitution Elasticity Estimate
		values here are for 2014 and are province-wide	Winter afternoon peak	N/A	2 hours	-0.01
Faruqui et al., 2014[126]	Connecticut Power & Light	Residential and small C&I pilot with TOU rate, CPP, and peak-time rebates (PTR); value here is an average across customer classes for CPP rates	N/A	N/A	N/A	-0.08
Faruqui et al., 2013[127]	Michigan Consumers Energy	Residential pilot with CPP and PTR; values are for both CPP and PTR, though the response was similar	N/A	CPP: 7.7 TOU: 2.0	4 hours	-0.11

[126] *See* Faruqui, A., Sergici, S., Akaba, L., *The Impact of Dynamic Pricing on Residential and Small Commercial and Industrial Usage: New Experimental Evidence from Connecticut*, 35 The Energy J. 137-160 (2014).

[127] *See* Faruqui, A., Sergici, S., Akaba, L., *Dynamic Pricing of Electricity for Residential Customers: The Evidence from Michigan*, 6 Energy Efficiency 571-584 (2013).

Study	Utility or Jurisdiction	Description	Season or customer type	Peak/Off-peak Price Ratio	Length of Peak Period	Substitution Elasticity Estimate
Faruqui and Sergici, 2011[128]	Baltimore Gas & Electric	Pilot with dynamic peak price (DPP) and PTR; DPP was implemented as TOU-CPP rates	N/A	CPP: ~15 TOU: 1.7	5 hours	-0.10
Potter et al., 2014[129]	Sacramento Municipal Utility District	Residential pilot with TOU-CPP, though differences in elasticities between the two were small; tiered rates	Default non-EAPR**	CPP: ~6-8 TOU: ~2-3 (Ratios are approximate; off-peak rates remained tiered)	3 hours	-0.07
			Default EAPR			-0.02
			Opt-in Non-EAPR			-0.18
			Opt-in EAPR			-0.09
Violette et al., 2007[130]	New Jersey Public Service Electric and Gas Company	Residential pilot with TOU-CPP and load control; estimate is for TOU only	N/A	CPP: 17 TOU: 2.7 (Ratios relative to base price)	5 hours	-0.07

[128] *See* Faruqui, A., Sergici, S., *Dynamic pricing of electricity in the mid-Atlantic region: econometric results from the Baltimore gas and electric company experiment,* 40 J. Regul. Econ. 82-109 (2011).

[129] *See* Potter, J., George, S., Jimenez, L., *SmartPricing Options Final Evaluation: The final report on pilot design, implementation, and evaluation of the Sacramento Municipal Utility District's Consumer Behavior Study* (2014).

[130] *See* Violette, D., Erickson, J., Klos, M., *Final Report for the MyPower Pricing Segments Evaluation* (2007).

Study	Utility or Jurisdiction	Description	Season or customer type	Peak/Off-peak Price Ratio	Length of Peak Period	Substitution Elasticity Estimate
Woo et al., 2013[131]	British Columbia	Residential pilot with TOU and load control; estimate is for TOU only	N/A	~2-11 (varies by plan)	4 or 5 hours single period or 7 hours morning + evening	-0.06

* The elasticity estimate is consistent with the "inner summer" estimate for TOU rates (no CPP) in 2003, but in 2004 the substitution elasticity estimate for customers on TOU fell to 0.0.

** EAPR refers to energy assistance program rate.

10.4.2. Lessons from Pilot Programs

To develop and refine this Updated AMF Business Case, the Company drew on experiences from the Worcester Pilot, which was developed to better understand how to effectively deploy AMF and positively affect customer energy behavior changes. This section contains a summary of lessons learned from that effort.

The Worcester Pilot began in 2013 with informational sessions followed by the deployment of AMF, as well as customer-facing technologies. In 2015, the Company introduced a novel rate structure to the pilot participants, consisting of TOU periods and a CPP rate. Customers could opt out of TOU/CPP to a peak-time rewards program instead.[132] The Worcester Pilot's objective was to empower customers to take control of their energy usage and discover savings with new grid technologies while retaining customer service quality. A post-deployment assessment by Navigant shows that the pilot was successful.[133] Customer satisfaction was strong, and participating customers lowered their energy bill by on average, $347 over the four-year pilot. Table 10-5 reflects the key findings from the Worcester Pilot assessment. The Company has

[131] *See* Woo, C.K., Li, R., Shiu, A., Horowitz, I., *Residential winter kWh responsiveness under optional time-varying pricing in British Columbia*, 108 Applied Energy 288-297 (2013).

[132] While TOU and CPP provide the customers commodity savings, PTR provides rewards for customers who curtail their energy load during specified days.

[133] *See* Navigant, National Grid Smart Energy Solutions Pilot, Final Evaluation Report (May 5, 2017) (Updated June 2019).

considered these lessons in developing its proposal for full-scale AMF implementation in Rhode Island.

Table 10-5: Worcester Smart Energy Solutions Pilot Assessment

Key Theme	Related Findings
Energy and demand savings for active customers	• Load reductions from 4% to 31% (0.12 to 0.60 kW) during CPP Events depending on the combination of rate and technology • 4.7% (29 kWh per month) weighted average energy savings across study groups given various enabling technologies for active CPP customers over the four years of the pilot
Demand savings for passive customers	• Savings increased from 1% to 4% for passive CPP customers and from 2% to 5% for passive PTR customers
Enabling technologies increased demand savings for active customers	• Customers with smart thermostats had the highest load reductions (18% - 31% on CPP and 10% to 27% on PTR) • Customers with in-home displays were next (11% to 18% on CPP and 0% to 9% on PTR), followed by customers with only web portal access (8% to 15% on CPP and 6% to 11% on PTR)
Bill savings	• Average per-customer bill savings of $347 total over the four years of the pilot for all customers on CPP • Average total rebates of $47 for conservation day peak events across all summers for all customers on PTR
High retention rate	• 98% customer retention rate at the end of 2018 (rates went live Jan. 1, 2015) • Most customers who opted out did so early on, with retention dropping just 0.4% from the end of 2015 to the end of 2018
Strong customer satisfaction	• 69% of customers rated their satisfaction at least a 5 on a 7-point scale at the end of 2016

Source: Navigant, *National Grid Smart Energy Solutions Pilot – Final Evaluation Report* (May 5, 2017; updated June 2019)

Likewise, the Clifton Park Demonstration in New York included a peak-time rewards program. As part of the New York AMI collaborative process, the Company's New York affiliate is working with Department of Public Service Staff to transitioning the Clifton Park project to test innovative pricing that will evaluate TVR offerings that could form the basis for a mass market default rate in New York. As innovative pricing concepts are further tested, the findings will further inform the approach to TVR in Rhode Island.

10.4.3. TVR design in the BCA Model

The TVR approach modeled in the BCA is based on the TOU/CPP rate structure for supply that the Company's affiliate successfully demonstrated in the Worcester Pilot. For the delivery component of the bill modeled in the BCA, the Company maintained the status quo of flat, volumetric rates. The supply rates related to energy splits the charges into on- and off-peak periods based on energy prices in ISO-NE. Capacity supply costs are recovered primarily through the CPP element. Based on feedback from the Worcester Pilot and in the New York AMI collaborative, the Company modeled CPP events limited to 70 hours per year to balance price increases in CPP events that were meaningful, but not too large, with events that would foster customer response. However, given the relatively higher share of capacity costs, the Company shifted some of the costs into the on-peak period. In the modeled Base Case scenario, the Company would have needed to recover an annual capacity cost of $122 million, which would have led to an on-peak CPP rate of 2.25 $/kWh. To moderate that effect, the Company set the on-peak CPP rate at 1.30 $/kWh and shifted the remaining capacity supply costs into the on-peak TOU energy supply rate.

The resulting total rates (including delivery) appear with the TOU time periods in Table 10-6. The peak periods were selected to capture distinct pricing trends in the wholesale market that vary by season under current conditions. The length of TOU periods in the rates that the Company surveyed ranged from 2 to 7 hours, while the TOU period lengths of the modeled rate range from 5 to 10 hours depending on the season. The 10-hour peak followed the rough contours of current ISO-NE pricing over summer months. In the Worcester Pilot, customers adapted to the longer 12-hour peak period with modest load-shifting in their energy usage.

In the modeled rate, the peak-to-off-peak ratio is set at 1.43. Based on the elasticities shown in Table 8-4, on-peak energy is modeled to decrease by 1.8% to 5.4% under this rate design (with corresponding off-peak increases of 0.8% to 2.4%). The on-peak savings levels bracket the Worcester Pilot results (4.7%) listed in Table 10-5, which had a longer on-peak period (8am to 8pm) and lower peak-off-peak price ratio (1.22).

Many surveyed TOU rates utilized slightly higher peak/off-peak price ratios than the modeled rate. The surveyed rates contained a wide range of CPP/off-peak price ratios, which includes the modeled ratio of 9.42. The price responsiveness curves developed by Faruqui[134] show diminishing returns of peak reductions as price ratios increase. To mimic this plateauing effect, the Company capped the maximum customer peak demand reduction at 20% based on the reports in Table 10-4. Because the CPP/off-peak ratio is so large, this customer response cap is engaged at every elasticity investigated (recall that elasticities associated with each case analyzed are reported in Table 8-3. The increase in CPP effectiveness beyond that seen in the Worcester

[134] *See* Faruqui, A., & Palmér, J., *The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity* (2012).

Pilot for participants without enabling technology is reasonable given the smaller number of peak hours (the pilot allowed for 30 CPP days) and a higher CPP/off-peak price ratio.

There are likely to be differences between the rate modeled here to support the BCA and the Company's proposal for TVR that it plans to implement. For example, there may be structural difference with respect to the number or timing of periods or the method by which capacity costs are recovered. Secondly, the Company may incorporate forward-looking analyses to adapt to changing energy market characteristics while adhering to the Docket 4600 principles.

Table 10-6: TOU/CPP total energy rates

Months	Peak Period	On-peak Price (¢/kWh)	Off-peak Price (¢/kWh)
December-March	7:00-12:00 16:00-21:00	19.66	13.79
April-May	17:00-22:00	19.66	13.79
June-September	11:00-21:00	19.66	13.79
October-November	7:00-12:00 16:00-21:00	19.66	13.79

CPP calls are limited to 70 hours per year; energy during these calls is priced at 1.30 $/kWh

Though the BCA only considers the single TOU/CPP rate design for the purposes of analysis, combinations of the sensitivities considered can serve as proxies for other rate design options. The Company provides four examples of broad rate design options in Table 10-7 and the cases quantified in this filing that best approximate them. From the perspective of the BCA model, the only manifestations of the TVR design are the savings from MWh of energy use shifted and MW reduced. Since the fraction of MWh or MW shifted is determined by both the price ratio and customer elasticity, changing the latter can approximate the impact of changing the former under uncertainties about both the final design and actual customer preferences.

In the table, the "effect on participation" field indicates the number of customers that would see a TVR signal. For rate structures that do not include delivery TVR, this number could be high or low depending on if the rate is applied as an opt-in or opt-out rate. The fields for "effect on customer response" are independent of the participation rate – these are meant to represent the effect on a single customer who sees the TVR signal. Given this representation, the total impact across all customers for a given rate structure requires multiplication of the effect of customer response by the effect on participation.

Table 10-7: Examples of broad TVR design options and how they would be modeled within the structure of the BCA model. The rightmost column states the combination(s) of participation and customer response assumptions in the current analysis that best approximates each given TVR design.

Rate Structure	Effect on Participation	Effect on customer response (energy)	Effect on customer response (demand)	Case(s) best approximating effect
Mild TOU+CPP supply Flat $/kWh delivery (used in BCA)	Low High	Low High	Low High	Opt-in Low Opt-out Low
Strong TOU+CPP supply Flat $/kWh delivery	Low High	Low High (high on/off-peak price ratio)	Low High (high CPP/off-peak price ratio)	Opt-in High Opt-out High
Strong TOU+CPP supply $/kWh delivery TVR	Low High (all customers see delivery TVR)	Low High (very high on/off-peak price ratio)	Low High (high CPP/off-peak price ratio)	Opt-out High
Strong TOU+CPP supply $/kW delivery TVR	Low High (all customers see delivery TVR)	Low High (high on/off-peak price ratio)	Low High (high CPP/off-peak price ratio and demand charge)	Opt-out High

As an example, consider the final row: strong TOU/CPP supply with $/kW delivery TVR, a design that is not modeled in the BCA. In this case, a TOU/CPP rate with a large on-peak/off-peak price ratio on the supply part of the bill is paired with a residential demand change that discourages usage during peak hours – this could be transmission-system peak and/or distribution-system peak depending on the ambition of the rate design. The time-varying nature of the delivery charge means that even customers who migrate to third-party suppliers still see a TVR price signal on part of their bill, which can be approximated by a high participation percentage. The strong price signal in the commodity charge leads to large energy shift away from the peak period. And the combination of the CPP signal and the demand charge results in a very strong signal to reduce peak demand. Given this combination of factors, the benefits produced by this unmodeled rate could be similar to those produced by the modeled Opt-out High case in the BCA.

10.4.4. <u>Customer Response to Achieve Cost-Effectiveness</u>

The benefits from customer response help increase the cost-effectiveness of the AMF program. Figure 10-1 and Figure 10-2 illustrate the level of TVR enrollment and customer response that will produce BCA ratios greater than 1.0.

As described in this Updated AMF Business Case, several variables are captured by the term "customer response" (on-peak energy usage decrease, off-peak energy usage increase, peak demand decrease, total usage conservation, and time to reach steady-state savings levels). The variables appear along the vertical axis of the figures, as it is reasonable to assume that they change in concert. The horizontal axis presents different TVR enrollments centered around the assumed opt-out or opt-in percentages used in the BCA model.

Absent any customer response to TVR or energy insights/bill alerts, the NPV benefits total $241 million compared to costs of about $224 million. This means that customer-driven benefits are not required to guarantee cost-effectiveness. Figure 10-1 and Figure 10-2 show how any customer response improves the program cost-effectiveness and that any modest response assumption leads to a BCA ratio of at least 1.32.

Within a given TVR enrollment case (opt-out or opt-in) the BCA ratios change gradually as specific enrollment percentages change. This is because of the large fraction of benefits linked to energy insights/bill alerts and TVR pricing of EV load, neither of which are tied directly to TVR participation percentages. The Company finds these assumptions reasonable: customers receive usage data and bill alerts regardless of enrollment in TVR, and EV owners are likely to stay on TVR rates (through the Company or a third-party supplier) to access cheap off-peak charging. This mild dependence on participation provides confidence in the program's ability to achieve cost-effectiveness despite uncertainty around the number of customers that may migrate to third-party supply service.

Benefit Cost Ratios for RI Test – RI+NY Deployment, High DER Adoption

On-peak energy reduction	Off-peak energy increase	Peak load reduction	Years to steady-state response	Energy Insights conservation	TVR Opt-out participation percentage						
					70%	75%	80%	85%	90%	95%	100%
1.2%	-0.56%	20.0%	5.0	0.6%	1.97	1.99	2.02	2.04	2.06	2.09	2.11
1.4%	-0.62%	20.0%	5.0	0.8%	2.01	2.04	2.06	2.09	2.11	2.13	2.16
1.5%	-0.68%	20.0%	5.0	1.1%	2.06	2.08	2.11	2.13	2.16	2.18	2.20
1.6%	-0.74%	20.0%	5.0	1.3%	2.10	2.13	2.15	2.18	2.20	2.22	2.25
1.8%	-0.80%	20.0%	5.0	1.5%	2.15	2.17	2.20	2.22	2.25	2.27	2.29
1.9%	-0.86%	20.0%	5.6	1.7%	2.19	2.21	2.23	2.26	2.28	2.30	2.33
2.0%	-0.92%	20.0%	6.1	1.9%	2.22	2.25	2.27	2.29	2.32	2.34	2.36
2.2%	-0.97%	20.0%	6.7	2.2%	2.26	2.28	2.31	2.33	2.35	2.37	2.40
2.3%	-1.03%	20.0%	7.2	2.4%	2.30	2.32	2.34	2.37	2.39	2.41	2.43
2.4%	-1.09%	20.0%	7.8	2.6%	2.34	2.36	2.38	2.40	2.42	2.44	2.46
2.6%	-1.15%	20.0%	8.3	2.8%	2.37	2.40	2.42	2.44	2.46	2.48	2.50
2.7%	-1.21%	20.0%	8.9	3.1%	2.41	2.43	2.45	2.47	2.49	2.51	2.53
2.8%	-1.27%	20.0%	9.4	3.3%	2.45	2.47	2.49	2.51	2.53	2.55	2.57
3.0%	-1.33%	20.0%	10.0	3.5%	2.48	2.51	2.53	2.55	2.57	2.58	2.60
3.1%	-1.39%	20.0%	10.6	3.7%	2.51	2.54	2.56	2.58	2.60	2.62	2.64
3.2%	-1.45%	20.0%	11.1	3.9%	2.54	2.57	2.60	2.62	2.64	2.65	2.67

Figure 10-1: Opt-out BCA ratios as a function of customer response (vertical dimension) and TVR enrollment (horizontal dimension). Shading indicates the value of the BCA ratio, and the two boxed values indicate the high and low bounds of customer response used in the model.

Benefit Cost Ratios for RI Test – RI+NY Deployment, High DER Adoption

On-peak energy reduction	Off-peak energy increase	Peak load reduction	Years to steady-state response	Energy Insights conservation	TVR Opt-in participation percentage						
					5%	10%	15%	20%	25%	30%	35%
1.9%	-0.85%	20.0%	2.0	0.6%	1.32	1.39	1.46	1.53	1.60	1.66	1.72
2.2%	-0.97%	20.0%	2.0	0.8%	1.37	1.44	1.51	1.58	1.64	1.71	1.77
2.4%	-1.09%	20.0%	2.0	1.1%	1.41	1.49	1.56	1.63	1.69	1.75	1.81
2.7%	-1.21%	20.0%	2.0	1.3%	1.46	1.53	1.60	1.67	1.74	1.80	1.86
3.0%	-1.33%	20.0%	2.0	1.5%	1.50	1.58	1.65	$\boxed{1.72}$	1.78	1.85	1.91
3.3%	-1.45%	20.0%	2.3	1.7%	1.55	1.62	1.69	1.76	1.83	1.89	1.95
3.5%	-1.58%	20.0%	2.7	1.9%	1.59	1.67	1.74	1.81	1.87	1.93	1.99
3.8%	-1.70%	20.0%	3.0	2.2%	1.64	1.71	1.78	1.85	1.91	1.98	2.04
4.1%	-1.82%	20.0%	3.3	2.4%	1.69	1.75	1.82	1.89	1.96	2.02	2.08
4.3%	-1.94%	20.0%	3.7	2.6%	1.73	1.80	1.87	1.94	2.00	2.06	2.12
4.6%	-2.06%	20.0%	4.0	2.8%	1.78	1.84	1.91	1.98	2.05	2.11	2.17
4.9%	-2.18%	20.0%	4.3	3.1%	1.82	1.89	1.95	2.02	2.09	2.15	2.21
5.1%	-2.30%	20.0%	4.7	3.3%	1.87	1.93	2.00	2.06	2.13	2.19	2.25
5.4%	-2.43%	20.0%	5.0	3.5%	1.91	1.98	2.04	$\boxed{2.11}$	2.17	2.23	2.30
5.7%	-2.55%	20.0%	5.3	3.7%	1.96	2.02	2.09	2.15	2.21	2.28	2.34
6.0%	-2.67%	20.0%	5.7	3.9%	2.00	2.07	2.13	2.19	2.25	2.32	2.38

Figure 10-2: Opt-in BCA ratios as a function of customer response (vertical dimension) and TVR enrollment (horizontal dimension). Shading indicates the value of the BCA ratio, and the two boxed values indicate the high and low bounds of customer response used in the model.

10.5. AMF Cost and Benefit Details

10.5.1. Mapping of Docket 4600 Benefit Categories to the AMF BCA

Table 10-8 lists each category of the Docket 4600 Framework and indicates if each category is quantified in this Updated AMF Business Case BCA. The manner in which categories either are factored into the BCA or omitted appears in the rightmost column. Actual values of included categories appear in Table 8-1. A more thorough description of unquantified categories appears in the more broadly scoped GMP.

Table 10-8: Benefit categories included in the Docket 4600 Framework and how they are included in the BCA model. For benefits that are excluded from the model, the table provides the reason for exclusion.

	Benefit Category	Quantified in filing?	Treatment in AMF BCA Or reason for exclusion
Power Sector Level	Energy Supply & Transmission Operating Value of Energy Provided or Saved	Yes	Included in avoided energy costs
	REC Value	Yes	Included in avoided energy costs as Embedded CO2 Benefit
	Retail Supplier Risk Premium	Yes	8% supplier markup included in avoided energy and capacity costs
	Forward Commitment Capacity Value	Yes	Capacity market savings with 3-year lag. Included for CPP
	Forward Commitment: Avoided Ancillary Services Value	No	Excluded because ancillary services would be very small
	Electric Transmission Capacity Value	Yes	Included in T&D benefits
	Net Risk Benefits to Utility System Operations from DER Flexibility & Diversity	No	Likely very little value for AMF, and AMF not assumed to incentivize additional DER adoption
	Option Value of Individual Resources	No	Difficult to quantify outside of portfolio analysis of multiple resources.
	Investment Under Uncertainty: Real Options Value	No	Likely small impact
	Energy Demand Reduction Induced Price Effect (DRIPE)	Yes	Intrastate DRIPE included, with ROP DRIPE impacts presented as a sensitivity
	GHG Compliance Costs	Yes	Included in avoided energy costs as Embedded CO2 Benefit. RGGI costs disaggregated from market prices and included separately

	Benefit Category	Quantified in filing?	Treatment in AMF BCA Or reason for exclusion
	Criteria Air Pollutant and Other Environmental Compliance Costs	No	Costs may be embedded in market prices but are not quantified or disaggregated. Likely very small
	Innovation and Learning by Doing	No	Not applicable to AMF
	Distribution Capacity Costs	Yes	Included as a benefit for managed EV charging, and a side benefit of TVR
	Distribution Delivery Costs	Yes	Benefits from reduced operational and infrastructure costs drive much of the BCA
	Distribution System Performance	Yes	Benefits from conservation voltage reduction (CVR / VVO) are included
	Utility Low Income	Yes	Improvements in bad-debt write-offs are calculated and shown in a sensitivity, but they are excluded from base RI Test as they are transfers between ratepayers
	Distribution System and Customer Reliability/Resilience Impacts	Yes	Included for GMP and in Societal Outage Management benefit of AMF
	Distribution System Safety Loss/Gain	Yes	Included as reduction in damage claims for AMF
Customer Level	Program Participant/Prosumer Benefits	No	Not included because of the wide range of customer options and customer non-energy benefits related to uncertain potential customer actions in response to TVR
Customer Level	Participant non-energy benefits: oil, gas, water, waste water	No	Incremental EV adoptions may result from improved ability to facilitate home charging but excluded gasoline savings and vehicle incremental costs from the analysis to avoid double-counting with EV initiatives
Customer Level	Low-Income Participant Benefits	No	Likely small for TVR (relative to a program like EE)
Customer Level	Consumer Empowerment & Choice	No	Not applicable to TVR envisioned for the AMF rollout
Customer Level	Non-participant Rate and Bill Impacts	Yes	Quantified at the aggregate utility level, but not included in RI Test
Societal	GHG Externality Cost	Yes	Non-embedded CO_2 costs (incremental to the RGGI cost) are included
Societal	Criteria Air Pollutant and Other Environmental Externality Costs	Yes	Non-embedded NOx costs are included

	Benefit Category	Quantified in filing?	Treatment in AMF BCA Or reason for exclusion
	Conservation and Community Benefits	No	Likely little or no impact for AMF
	Non-energy benefits: Economic Development	Yes (sensitivity only)	Included as a sensitivity. Potentially a large benefit, but relatively high uncertainty can discredit precision of other BCA components
	Innovation and Knowledge Spillover (Related to demonstration projects and other RD&D)	No	Not applicable, as not a demonstration program
	Societal Low-Income Impacts	No	Too difficult to quantify. Could be a large benefit for some households, but likely small for Rhode Island as a whole
	Public Health	Yes	Included as related to change in grid level power production
	National Security and US International Influence	No	Expected to be minimal in foreseeable future due to US oil export balance, and not expected to be impacted by TVR

10.5.2. Details of Economic Impact Analysis

The Company and GMP and AMF Subcommittee members agree that economic development benefits are important. However, including these benefits in the base case BCA results can be problematic due to the relatively high uncertainty associated with these benefits, which can discredit the precision of other BCA components. Additionally, because the benefits can be large, they create a "masking" effect. This section describes the economic impact modeling and efforts to limit uncertainty.

Brattle Group Study

The Brattle Group addressed these issues in a February 2019 report commissioned by the Company for the Rhode Island Energy Efficiency Resource Management Collaborative (EERMC).[135] In the report, Brattle recommended an approach to estimating the economic development benefits of EE investments that avoids double counting and overestimation. The approach involves estimating all economic impacts related to the investments, both positive and negative. For example, besides positive construction impacts of EE program spending, negative economic impacts should also be considered such as decreased T&D construction and power sector activity due to reduced peak demand.

[135] *See* Mark Berkman and Jurgen Weiss, *Review of the RI Test and Proposed Methodology*, Prepared for National Grid, by The Brattle Group (February 2019).

Brattle also recommended an approach for identifying economic benefits and costs already included in the BCA so that they would not be counted twice. Finally, Brattle recommended using net Rhode Island GDP in the BCA to measure the societal impact of economic development benefits such as job years, incomes and the regional competitiveness of firms. The approach was accepted by the EERMC and is being used by the Company in the Rhode Island Test, the BCA model used to screen investments for Rhode Island's Energy Efficiency Program Plan (EEPP).

While the Company followed this same approach in estimating the economic development benefits of the proposed AMF investments, there is currently more uncertainty around the AMF benefits and costs than there is around the EEPP investments, including the timing of the ratepayer costs. For this reason, the Company includes the net AMF GDP impacts along-side the BCA as a sensitivity but does not add them to the BCA calculations.

Overview of AMF Economic Development Benefits

Spending on AMF implementation is expected to total $349 million nominally and have net positive impacts on the Rhode Island economy. Table 10-9 summarizes these impacts, as well as the economic impacts that are not captured by the AMF BCA but should be considered.

Table 10-9 shows that local AMF implementation spending, which excludes spending on equipment and specialized labor procured from outside of Rhode Island, has a 20-year NPV of $49.8 million. This is expected to add 467 job years and an NPV of $38.7 million in GDP to the Rhode Island economy due to increased demand for construction, engineering, project management, consulting, professional services and other industries involved in planning and implementing the AMF. The impacts are felt mainly in AMF years 3 and 4, when AMF meter implementation takes place.

Over time, these economic gains are offset by reduced spending on meter reading, T&D capacity, and generation, all due to AMF implementation. Reduced meter reading spending leads to the loss of 523 job years and an NPV of $29.5 million in Rhode Island GDP. Reduced spending on T&D and electric generation causes the loss of 630 job years and an NPV of $33.4 million in GDP. These losses are partially offset by the positive impact of electric reliability improvements and local health benefits due to the AMF. These are amenity improvements that make Rhode Island a more desirable place to live, leading to increased net in-migration and, over time, 172 additional job years and an NPV of $7.3 million in additional Rhode Island GDP.

While the positive economic impact of AMF-related amenity improvements is not enough to offset the negative economic impact of reduced spending on meter reading, generation and T&D capacity, the impact on net customer benefits is. Net customer benefits equal total AMF benefits minus total AMF costs. The net electricity cost savings to customers add 2,918 job years and an NPV of $148.2 million to Rhode Island GDP after the AMF is implemented.

Accounting for all these impacts, the AMF investments are expected to create a net of 2,404 job years in Rhode Island; add an NPV of $131.1 million to Rhode Island GDP; increase real personal income by an NPV of $281.9 million; and raise state tax revenues by an NPV of $25.2 million. These are net economic development benefits to the State of Rhode after all costs have been paid.

Table 10-9: AMF Project Economic Development Impacts. State of Rhode Island and BCA Consideration

	Spending (20-year NPV, M$)	Job Years*	GDP (20-year NPV, M$)	Personal Income (20-year NPV, M$)	State Tax Revenue (20-year NPV, M$)
Local AMF Implementation Spending	$49.8	467	$38.7	$30.4	$1.9
Reduced Meter Reading Spending	-$38.9	-523	-$29.5	-$21.5	-$1.4
Reduced T&D Capacity Spending	-$44.0	-630	-$33.4	-$24.6	$5.9
Reduced Power Sector Spending	$36.9	172	$7.3	$11.7	$0.7
Net Customer Benefits (After Costs)	$223.1	2,918	$148.2	$285.8	$18.0
Net State of Rhode Island	$226.9	2,404	$131.1	$281.9	$25.2
Net for BCA Consideration		2,090	$115.9	$253.6	$22.9

* A “job year” is one job for a period of one year. Job year losses associated with reduced meter reading spending include eliminated meter reader positions and their indirect and induced employment impacts.

BCA Consideration

In Table 10-9, some of the net economic development benefits to Rhode Island are already captured in the BCA. Specifically, the direct economic impact of net customer benefits, which are reduced electricity costs to residential and C&I customers, are included. However, the secondary impacts of these cost reductions, known as indirect and induced impacts, are not included in the BCA but should be considered. For residential customers, these impacts consist of increased supply chain and service sector activity as customers spend a portion of their electricity cost savings locally. For C&I customers, this includes positive local supply chain and output effects as firms increase production due to lower electricity costs. On the other hand, the total (direct, indirect and induced) economic impact of AMF implementation, reduced meter reading, T&D capacity and power sector spending are not currently included in the BCA. The final row of Table 10-9 adds these economic impacts together plus the indirect and induced impact of net customer benefits. The overall societal impact is measured by net GDP, which encompasses job years, incomes, state tax revenues and the increased competitiveness of Rhode Island business firms. This has a 20-year NPV of $115.9 million and is considered alongside the BCA as a sensitivity.

Methodology

Economic impacts were estimated using the REMI regional economic model of the Rhode Island economy. REMI has been used in the industry for over 30 years to estimate the economic development impact of various investments, programs and policy proposals. REMI has over 150 U.S. and international clients including the Rhode Island Department of Revenue; as well as other state, federal, and local government planning agencies; non-profit research organizations; energy consultants; universities; and utilities. National Grid leases a 169-sector version of REMI's Rhode Island model.

Only local spending was considered in the REMI analysis. Spending on materials to be purchased from outside of the region was not included as this will not have a significant impact on Rhode Island economic activity. Also, spending on specialized labor available only outside of Rhode Island was not included. Spending on local labor was allocated between general construction, electrical contractors and professional services before input to REMI. The REMI model estimates the proportion of this increase in Rhode Island demand that will be met locally versus from outside of Rhode Island. Net customer benefits were input into REMI as reduced electricity costs, allocated to residential and C&I customers based on load. REMI estimated the local economic impact of these electricity cost savings.

10.6. PST Advisory Group Subcommittee Overview

Power Sector Transformation (PST) GMP/AMF Subcommittee Meetings:

- Full Subcommittee Meetings
  - AMF Collaborative Kick-off (October 26, 2018)
  - Pilot Learnings (November 16, 2018)
  - Filing Schedule; GMP Plan; AMF BCA Overview (November 27, 2018)
  - GMP Impacts/Opportunities; AMF Customer Value Streams and Data Access
  - (December 13, 2018)
  - GMP Functionalities; GMP BCA; AMF Customer Engagement Plan (January 10, 2019)
  - Docket 4600 Alignment (February 14, 2019)
  - Alignment with ASA Requirements (February 27, 2019)
  - AMF Proposal; GMP BCA Methodology (March 28, 2019)
  - AMF BCA Deep Dive (April 18, 2019)
  - Technical Session Preview; Path Forward; Data Governance (November 1, 2019)

- PST Advisory Quarterly Meetings
  - January 31, 2019
  - April 25, 2019
  - July 22, 2019
  - December 17, 2019
  - March 31, 2020
  - September 15, 2020

- RI PUC Technical Sessions
  - April 9, 2019
  - November 5, 2019
  - September 24, 2020

- Small Group Meetings
  - AMF Collaborative Plan (September 21, 2018)
  - Alternative Business Models (October 11, 2018)
  - GMP & AMF Status Update (October 10, 2019)
  - Collaboration Schedule; Metrics & PIMs Roadmap (October 29, 2019)
  - PUC Technical Workshop Debrief; Data Governance Review (November 7, 2019)
  - Metrics & PIMs Roadmap (November 19, 2019)
  - Revenue Requirements; Cost allocation; Bill Impacts (December 6, 2019)
  - AMF Business Case (June 24, 2020)
  - Customer Engagement Plan; Metrics & PIM's Roadmap (July 17, 2020)
  - Data Governance; Time Varying Rates (July 30, 2020)
  - Grid Modernization Plan (September 1, 2020)

List of PST Meeting Participants:

- National Grid
- Energy and Environmental Economics (E3)
- Division of Public Utilities and Carriers (DPUC)
- Office of Energy Resources (OER)
- Regulatory Assistance Project (RAP)
- Synapse
- Northeast Clean Energy Council
- Center for Justice for the Wiley Center
- Conservation Law Foundation (CLF)
- Acadia Center
- Green Energy Consumers Alliance
- Vote Solar
- The Energy Council of Rhode Island (TEC-RI)
- Direct Energy (Retail Electric Suppliers Association)
- City of Providence
- Washington County Regional Planning Commission

10.7. Docket No. 4600 Goals and Alignment with GMP and AMF Objectives

Alignment Between Docket No. 4600 Goals, GMP Objectives, and AMF Objectives

Docket No. 4600 Goals	RI GMP Objective
Empower customers to manage their costs	1) Give customers more energy choices and information
Customer education and engagement programs to provide all customers with the information and tools to optimize their electricity consumption	
Provide opportunities to reduce energy burden	
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)	2) Ensure reliable, safe, clean, and affordable energy to benefit Rhode Island customers over the long term
Strengthen the Rhode Island economy, support economic competitiveness, and retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	
Appropriately charge customers for the cost they impose on the grid	
Appropriately compensate the distribution utility for the services it provides	
Address the challenge of climate change and other forms of pollution	3) Build a flexible grid to integrate more clean energy generation
Appropriately compensate DERs for the value they provide to the electricity system, customers, and society	
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	

Note that the text in bold indicates AMF specific functionalities and objectives.

1) Give customers more energy choices and information
    a) Inform customers about their energy use and energy choices:
        i. **Provide personalized insights and actions to customers based on more granular usage data (e.g., high-bill alerts, appliance-level load disaggregation);**
        ii. **Enable customer connections and data sharing with third parties (e.g., Green Button Connect); and**
        iii. **Enable automated notifications for customer outages.**

    b) **Provide enhanced energy management capabilities (e.g., CEMP).**

    c) Enable customers to invest in their own DER technologies and promote investment in areas that are most cost effective for these resources:
        i. Provide transparency concerning system needs and opportunities to interested stakeholders, thereby fostering a more collaborative approach to distribution system planning and operations.

    d) Ensure that all customer and grid facing data is kept safe, secure, private, stored, and maintained through robust data governance and management

2) Ensure reliable, safe, clean, and affordable energy to Rhode Island customers over the long term:

    a) Develop a more efficient grid through greater monitoring and control of grid- and **customer-side devices**
    b) Ensure safety and reliability are maintained or improved with increasing levels of DER adoption.
    c) Ensure new pricing and allocation mechanisms to attribute costs and benefits more equitably
        i. **Enable alignment of customer energy costs with their impact on the grid:**
            (a) Develop and leverage more effective customer load management programs; and
            (b) Enable TVR.

3) Build a flexible grid to integrate more clean energy generation

    a) Enable higher penetration of clean DERs into the grid:
        i. **Support DER optimization through more granular data and control at the customer level.**

b) Effectively manage emerging two-way power flows in a reliable, safe, clean and affordable manner:
   i. **Improve grid planning and operations capabilities and ability to integrate more clean energy integration;**
   ii. **Provide granular, real-time values that allow for improved load and DER forecasts to be leveraged for planning needs; and**
   iii. Better integrate new grid-connected devices and remote-control in a reliable and secure fashion.

c) Enable better assessment of the locational and temporal value DER may provide to the electric system.

Appendix 10.8
Worcester Pilot

10.8. Worcester Pilot Final Evaluation Report

The Final Evaluation Report for the Worcester Pilot is provided in a separate appendix document.

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To: Beth Delahaij and Bill Jones, National Grid

From: Becca Kuss, Carly Olig, Steven Tobias, and Ken Seiden, Navigant

Date: July 25, 2019

Re: National Grid Smart Energy Solutions 2017 and 2018 – FINAL

This memo discusses demand, energy, and bill impacts for National Grid's Smart Energy Solutions pilot. The first section focuses on key findings from all 4 years of the pilot (2015-2018),[1] while the remainder of the memo discusses in-depth results from 2017 and 2018[2]. The 2015 and 2016 evaluations included both impact and customer experience results, while the 2017 and 2018 evaluations only included impact analyses.

Summary of Smart Energy Solutions Evaluation Findings

Smart Energy Solutions (SES or the pilot) is an innovative smart grid pilot deploying advanced meters, customer-facing technologies, and time-of-use (TOU) rates. A complete description of the pilot can be found in Navigant's 2015/16 report.[3] The initial pilot ran in 2015 and 2016 and was extended to 2017 and 2018.

Key process and impact findings across the lifetime of the pilot are summarized in Figure 1. These findings include demonstration of significant energy and peak event savings, the important role of technology, and high customer retention.

Figure 1. Key Findings from 2015-2018 SES Evaluations

Energy and Demand Savings for Active Customers	Enabling Technologies Increased Demand Savings for Active Customers	Bill Savings	High Retention Rate	Strong Customer Satisfaction
• Load reductions up to 31% (0.60 kW) during conservation day peak events depending on the combination of rate and technology • 4.7% (approximately 29 kWh per month) weighted average energy savings across the technology groups for active critical peak pricing (CPP) customers over the 4 years of the pilot	• Customers with smart thermostats had the highest load reductions (18%-31% on CPP and 10%-27% on peak time rebate, or PTR) • Customers with in-home displays (IHDs) were next (11%-18% on CPP and 0%-9% on PTR), followed by customers with only web portal access (8%-15% on CPP and 6%-11% on PTR)	• Average per-customer bill savings of $347 total over the 4 years of the pilot for all customers on CPP • Average total rebates of $47 for conservation day peak events across all summers for all customers on PTR	• 98% retention rate of customers in the pilot at the end of 2018 after rates went live on January 1, 2015 • The majority of customers who opted out did so early on, with retention dropping just 0.4% from the end of 2015 to the end of 2018	• 69% of customers rated their satisfaction with SES at least a 5 on a 7-point scale at the end of 2016

Source: Navigant analysis

Table 1 shows total and percentage demand and energy savings and total bill savings for residential customers in the pilot. Total savings are the sum of savings across all residential customers in the program. For the peak event savings, the total savings are shown for the average event, which is the

[1] The informational portion of the pilot began in 2013, rates went live in January 2015, and implementation ran through the end of 2018.
[2] Descriptions of the methodology used to estimate impacts are not provided in this memo but can be found in Navigant's 2015/16 report.
[3] Navigant. *National Grid Smart Energy Solutions Pilot*. 2017. Prepared for National Grid. (D.P.U 10-82)

average across all peak event hours across all peak events of each summer, and for the maximum event, which is the single Conservation Day with the highest average savings across the peak event hours. Percentage savings are the weighted average of savings across the residential technology/price plan groups, and are shown for all customers as well as active customers, which are those who have logged in to the WorcesterSmart web portal at least once or opted into technology levels 2 or higher. The bulk of total savings are generated by customers in Level 1 critical peak pricing (CPP), Level 2 CPP, and Level 4 CPP due to the large number of customers and high impacts for those groups.

Table 1. Total and Percentage Savings for Residential Customers: 2015-2018

Impact Category and Savings Type		2015 (20 Events)		2016 (20 Events)		2017 (8 Events)		2018 (25 Events)	
		Average Event*	Maximum Event**	Average Event*	Maximum Event**	Average Event*	Maximum Event**	Average Event*	Maximum Event**
Peak Event Savings	**Total Savings**	**0.55 MW**	**1.59 MW**	**1.02 MW**	**2.28 MW**	**0.50 MW**	**1.69 MW**	**0.41 MW**	**2.02 MW**
	Percentage Savings for **Active** Customers	16.8%	29.0%	16.8%	24.0%	11.5%	18.5%	8.9%	18.1%
	Percentage Savings for **All** Customers	3.9%	12.3%	7.2%	14.3%	2.9%	9.5%	2.5%	12.7%
Energy Savings ***	**Total Savings**	**210 MWh**		**1,570 MWh†**		**150 MWh**		**700 MWh**	
	Percentage Savings for **Active** Customers	4.3%		6.3%		3.9%		4.6%	
	Percentage Savings for **All** Customers	0.2%		2.0%		0.1%		0.9%	
Bill Savings‡		**$1.0 M**		**$0.8 M**		**$1.2 M**		**$0.9 M**	

* This is the total demand savings among all participants, averaged across all events in the summer of each year.

** This is the total demand savings for 6/23/2015, 7/25/2016, 7/7/2017, and 6/18/2018, the Conservation Days with the highest savings for each summer.

*** This includes energy savings for CPP customers only, as energy savings were not expected or found for peak time rebate (PTR) customers.

† The considerable increase in energy savings in 2016 was driven primarily by a spike in savings in July; Navigant did not find any evidence suggesting this result was erroneous. This is discussed more fully in Navigant's 2015/16 report.

‡ This includes total bill savings for CPP customers and rebates for PTR customers.

Source: Navigant analysis

For the CPP rate, average per-customer bill savings over the 4 years of the pilot were $786 for Level 2, $546 for active customers in Level 1, $336 for Level 4, $296 for Level 3, and $266 for passive customers in Level 1[4]. For most groups, bill savings were highest in 2015 and 2017 despite energy savings being the highest in 2016. Increases in energy savings do not necessarily produce increases in bill savings because of the high prices during peak events. For example, the highest energy savings occurred in July 2016, but that month did not produce high bill savings because National Grid called 11 peak events, increasing bills in that month for many customers.

[4] Passive customers still realize bill savings even without (or with negative) energy savings because the non-event peak price for CPP customers is below the Basic Rate. See Table 6 for a comparison of SES rates with Basic rates.

PTR customers averaged approximately $47 in total bill rebates over the 4 years of the pilot. Level 4 customers achieved the highest average rebate of $1.23 per event, active Level 1 customers averaged $0.66 per event, Level 2 customers averaged $0.62 per event, and passive Level 1 customers averaged $0.51 per event. Across the 4 years, PTR rebates were highest for most groups in 2018 because that year had the most events. However, Level 4 customers had the highest bill rebates in 2015, driven by the high thermostat setbacks that year.

Table 2 summarizes the events across all 4 years of the pilot; the first four rows summarize event characteristics while the last four summarize weather. Temperatures during peak events were relatively similar across all 4 years, but 2018 had considerably higher humidity during events than the other three years. Humidity averaged 63.2% during event hours in 2018 compared to 53.4% in 2015, the second most humid year. Thus, 2018 had the most events and the most event hours (175, which was the maximum allowed for the program). Additionally, events were longest in 2018, averaging 7 hours. The mildest year of the pilot was 2017 (average humidity was 47.4%), which had only 52 peak event hours. The average degree setback for smart thermostats during events decreased each year, going from 3.3°F in 2015 to 2.2°F in 2018.

Table 2. Annual Event Overview: 2015-2018

Statistic	2015	2016	2017	2018
Number of Events	20	20	8	25
Total Event Hours	135	139	52	175
Average Event Length in Hours	6.75	6.95	6.50	7.00
Average Degree Setback for smart thermostats during Events	3.3°F	2.6°F	2.4°F	2.2°F
Average Event Temperature	82.1°F	82.8°F	84.0°F	82.6°F
Average Maximum Event Temperature	84.9°F	85.8°F	85.6°F	85.2°F
Average Event Humidity	53.4%	52.5%	47.4%	63.2%
Average Event Dew Point	63.1°F	62.7°F	61.4°F	68.3°F

Source: Navigant analysis

While energy and bill savings remained mostly steady throughout the pilot,[5] demand impacts decreased. Navigant explored several hypotheses for why demand impacts fell, which are outlined in Figure 2. Although the demand savings were lower, they were still statistically significant. These hypotheses are further explored in the following paragraphs.

[5] Energy savings were higher in 2016 due to a spike in savings in July. Dollar savings were slightly higher in 2017 due to the low number of peak events called.

Figure 2. Hypotheses for Changing Demand Savings

Lower temperature setbacks occurred in each year of the pilot, leading to lower savings for customers with smart thermostats.

Longer events led to decreased savings as the event impacts tend to decay during the event.

Decreased engagement from active customers who did not continue to log in to the web portal over time and from disconnections of IHDs and smart thermostats.

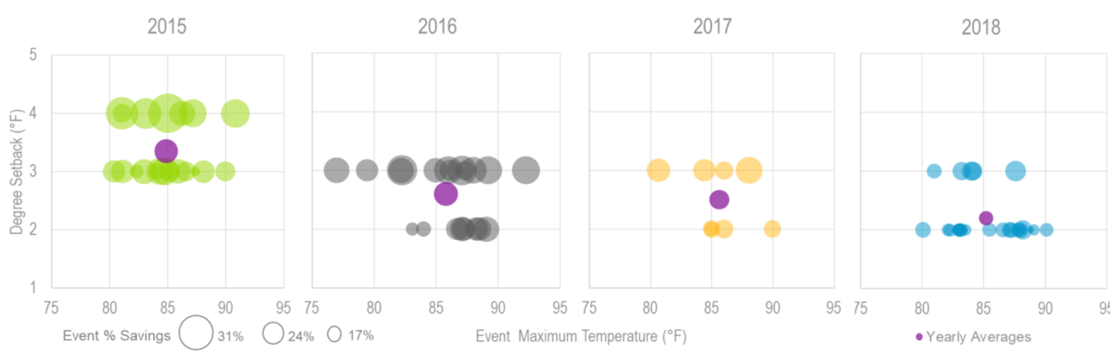
Increased load shifting to weekends resulted in less curtailable load as participants became more familiar with the program and changed habits to shift load away from peak hours.

Customer expectations for bill protection may have made them less motivated to curtail load after they were made whole in previous years. In a 2016 survey, 20% of CPP participants said knowledge of bill protection made them put "somewhat less" or "much less" effort into saving.

Notes: IHD refers to in-home device. Active participants are those who opted to receive one of the pilot technology packages or who had no technology but visited the program web portal at least once; any customers without technology who did not visit the web portal are characterized as passive.
Source: Navigant analysis

Figure 3 plots event temperatures (x-axis), degree setbacks (y-axis), and demand savings (size of data point) for Level 4 CPP customers by year. The trend of decreasing setbacks and smaller impacts is visible in the location and size of each data point. Additionally, events with higher degree setbacks had higher savings regardless of the outdoor temperature during the event.

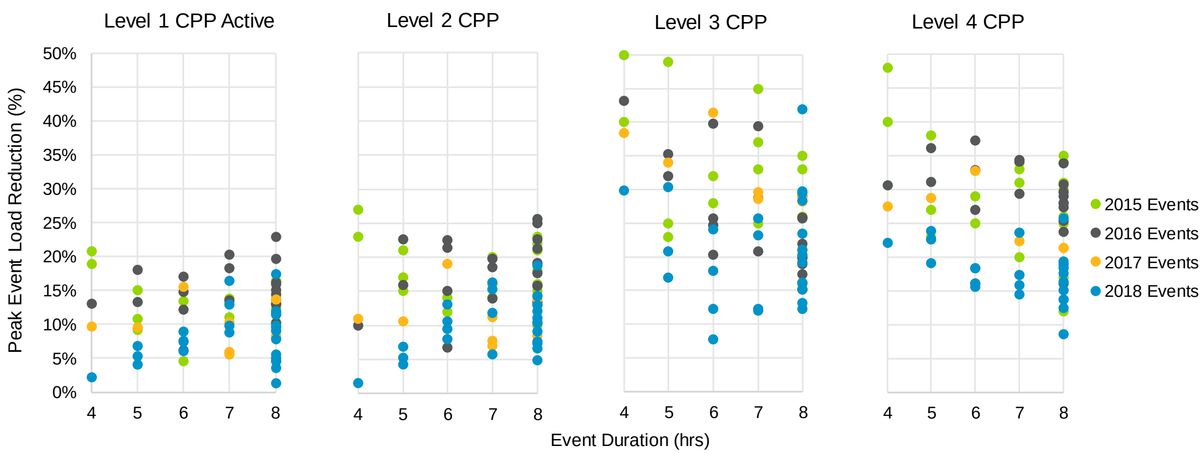
Figure 3. Level 4 CPP Event Temperatures, Setbacks, and Impacts: 2015-2018



Source: Navigant analysis

Figure 4 shows the average load reduction was smaller for longer events, especially among Level 3 and 4 customers who may have manually overrode the setbacks on their smart thermostats as events went on. Events were longest in 2018, which may have contributed to lower impacts. However, this effect is corollary and Navigant did not formally quantify the magnitude or certainty of the effect.

Figure 4. Peak Event Load Reductions (%) vs. Event Duration: 2015-2018

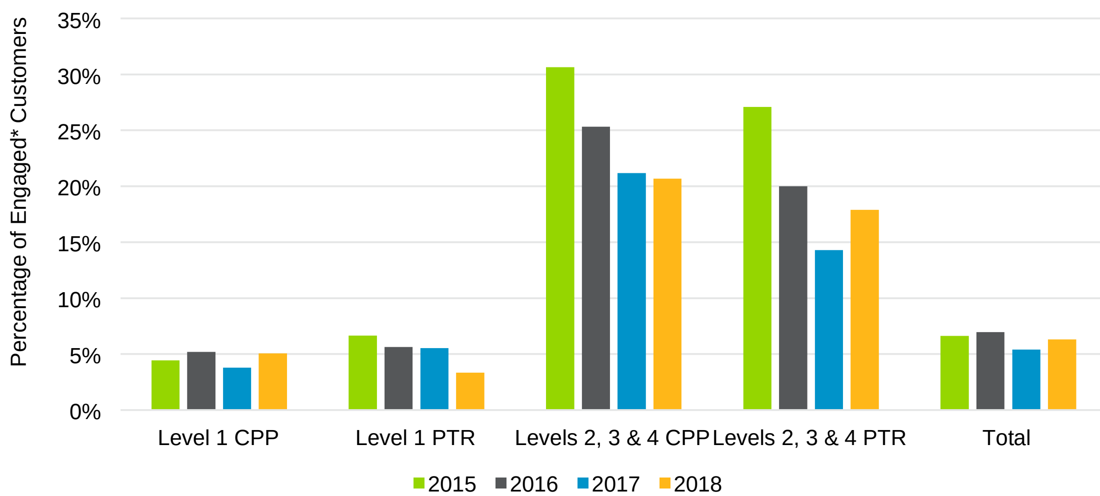


Source: Navigant analysis

Figure 5 and Figure 6 detail customer engagement throughout the pilot. Active customers are defined by one login to the WorcesterSmart web portal at any time; this definition does not consider recency or frequency of logins. In order to better characterize the level of ongoing engagement of customers, Navigant created a second definition of an "engaged customer" as one who logged into the WorcesterSmart web portal at least twice during the summer months from June to September. Figure 5 shows that Level 2, 3, and 4 CPP customers along with Level 1 PTR customers were less engaged over time. However, Level 1 CPP and Level 2, 3, and 4 PTR customers showed an uptick in engagement in 2018—likely due to the increased numbers of events that year.

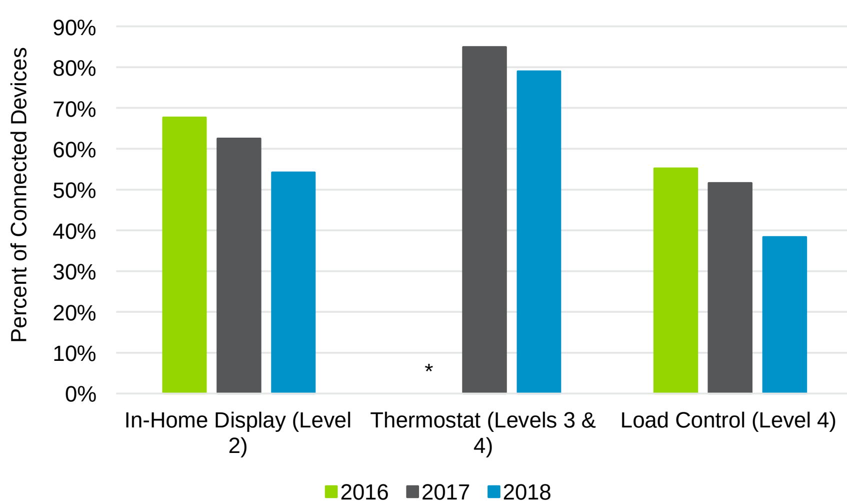
Additionally, the program defines technology levels at the time a customer opts in to a level and does not consider installation or connectivity of the technology. Figure 6 shows that the connectivity of IHDs, smart thermostats, and load control devices fell from 2016 to 2018 (data was not collected for 2015). Lower connectivity of the devices may have contributed to the lower impacts in 2017 and 2018 as compared to 2015 and 2016.

Figure 5. Engaged Customers Based on Web Portal Logins: 2015-2018



* Navigant defined engaged customers as those who logged in to the WorcesterSmart web portal at least twice over the summer months of June through September.
Source: Navigant analysis

Figure 6. Technology Connectivity: 2016-2018



Note: No connectivity data is available for 2015.
* Thermostat connectivity data is not available for 2016.
Source: Navigant analysis

Before and throughout the pilot, National Grid implemented a *listen, test, learn* approach based on on-the-ground conversations and reflections on the pilot. Several broad themes emerged regarding customer response to the pilot design and implementation. Impacts for active customers (13.0% peak load reduction and 4.7% average load reduction over the 4 years of the pilot) were near the 5% goals established through Section 85 of the Green Communities Act. In particular, the average load reduction estimate in each year was not statistically different from 5%, although the point estimate averaged across the 4 years was slightly below. Additionally, the majority of customers were satisfied with the pilot based on 2015 and 2016 surveys. Figure 7 summarizes key learnings from the 4 years of the pilot. Impact findings are based on all 4 years of the pilot, while customer experience findings are based on 2015 and 2016 (further evaluation of these topics was not conducted in 2017 and 2018).

Figure 7. Key Learnings from SES

SES shows the strength of opt-out design.

- The program enrolled approximately 12,000 participants, which is more than could have been recruited in an opt-in design.
- The retention rate after 4 years was 98%, which is higher than many comparable opt-in programs.
- Program satisfaction was strong, with 69% of participants rating the pilot at least a 5 on a 7-point scale after 2 years.

It is important to choose the default price plan and technology level in an opt-out program carefully.

- SES defaulted customers to the CPP rate and web portal, with no additional in-home technology.
- Approximately 91% of customers were still on the default price plan and 91% at the default technology level after the 4 years of the pilot.
- Although satisfaction was strong, default bias is likely to be a factor in customers staying on the default enrollment options in the opt-out design.

Long peak events and peak events called on consecutive days did not significantly affect savings or satisfaction.

- Despite calling more peak events (including on consecutive days) and longer peak events than similar programs, SES achieved similar satisfaction and savings.
- However, some customers did express a desire for shorter events ending earlier in the evening.

IHDs increased demand savings, but much of the total demand savings were achieved with just a web portal.

- Customers with in-home devices had significantly higher demand savings (up to 31%) than those without any technology (up to 15%).
- Customers without technology who visited the program web portal saved at least twice as much in each year as those who did not visit the web portal. This may be attributable to differences in motivation as well as to the web portal itself.
- Customers without technology made up approximately 90% of the participants in the pilot and approximately 55% of the total peak event savings.
- Customers with IHDs saved the most energy (up to 8.1%), followed by those with web portal access only (up to 6.4%). Those with smart thermostats had higher demand savings but lower energy savings.

Customers on the CPP rate saved more than those on the PTR rate.

- At each technology level, active customers on the CPP rate saved more than those on the PTR rate.
- Passive customers saved more on the PTR rate in 3 of the 4 years, but that could be due to a slightly higher level of engagement since they had to opt in to the PTR rate.
- The motivations to save during peak events on the CPP rate are greater than for the PTR rate, as customers face higher summer bills if they do not save on the CPP rate.

The PTR rate may be more appropriate than the CPP rate for those on fixed budgets or with health issues.

- Although the CPP rate saves money over the course of the year, bills do increase for many customers in the summer, potentially making the PTR rate a better choice for customers on a fixed or limited income.
- For those who have a limited ability to reduce their energy usage (because of elderly, ill, or limited mobility household members, pets who need cooler temperatures, electric medical equipment, etc.), the PTR rate may be more appropriate.

Information needs to be provided multiple times via multiple channels.

- Despite a plethora of communication from National Grid, half of customers without technology (i.e., IHD and/or PCT) did not know it was available, and of the 40% who knew it was available, many did not understand the benefits.
- Additionally, many customers (56%) did not realize they had the option to switch price plans.
- Based on focus groups conducted in the first and second years of the pilot, low income customers had low awareness of the rates and technology adoption despite the high potential benefits to this group.

Customers want options to personalize Conservation Day notifications.

- Customers cited issues with the amount and methods of Conservation Day notifications in 2015 and responded well to additional promotion and simplified personalization options in 2016. Surveys were not conducted in 2017 or 2018.

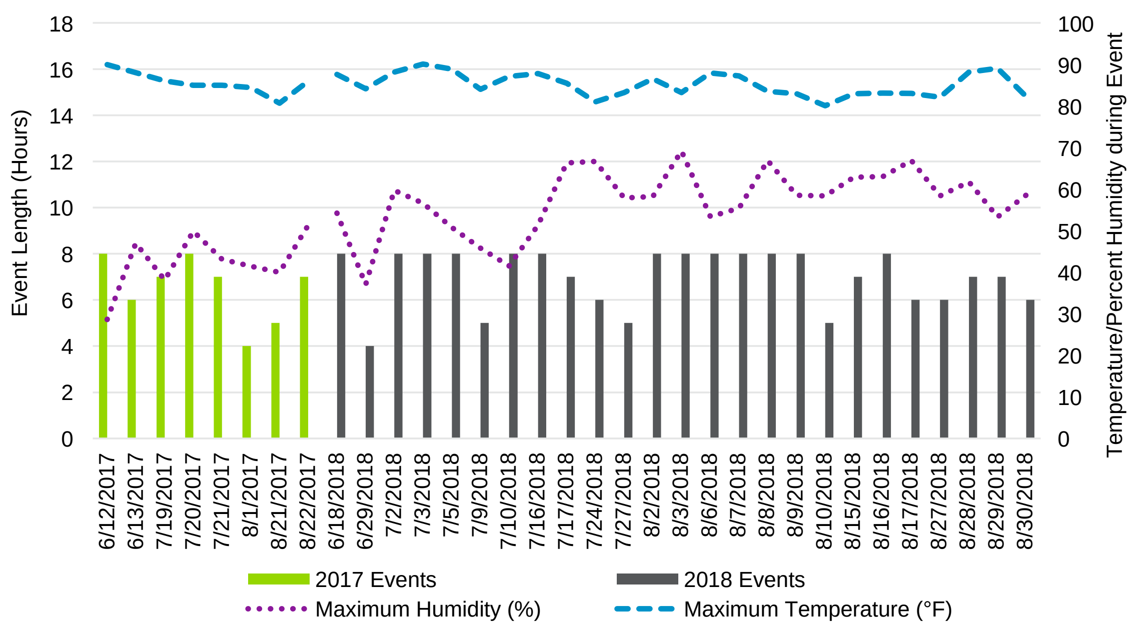
Source: Navigant analysis

The next section of this memo discusses program and customer information for 2017 and 2018 including customer counts and descriptions of the Conservation Day events. The sections that follow discuss the details of demand, energy, bill, and load shifting impacts from SES in 2017 and 2018.

Program and Customer Information

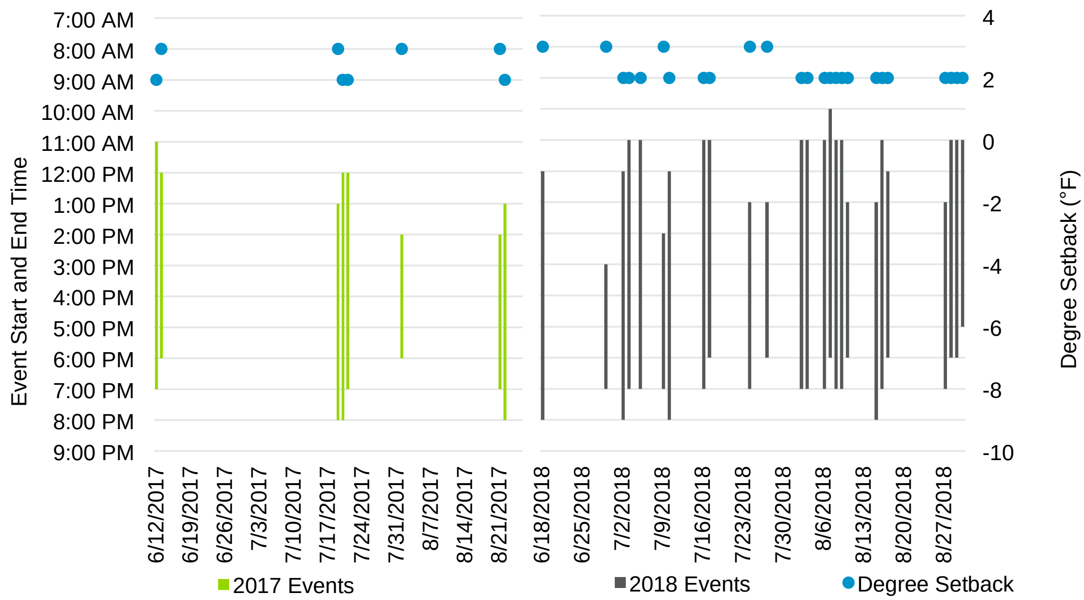
National Grid called eight peak events in 2017 and 25 in 2018. The length and weather conditions for each 2017 and 2018 peak event are shown in Figure 8. The year 2017 had the fewest events and event hours of any program year, with only 52 peak event hours, whereas 2018 had the most events and the most event hours (175, which was the maximum peak event hours allowed for the program). Figure 9 shows the start and end time along with the degree setback for each event. Temperatures during peak events were relatively similar across all 4 years of the pilot, but 2018 had considerably higher humidity during events than the other 3 years. Humidity averaged 63.2% during event hours compared to 53.4% in 2015, the second most humid year. The average degree setback for smart thermostats during events decreased each year, going from 3.3°F in 2015 to 2.2°F in 2018.

Figure 8. Summary of Peak Event Length, Temperature, and Humidity: 2017-2018



Source: Navigant analysis

Figure 9. Summary of Peak Event Start and End Times and Degree Setback: 2017-2018



Source: Navigant analysis

Table 3 shows the distribution of customers in the various technology levels and price plans in 2017 and 2018. The portion of customers subscribed to Level 1 has remained steady since 2016 at 91%. The portion of active[6] customers has increased from 24% in 2016 to 28% in 2018. Approximately 96% of customers were on the default CPP rate in 2017 (similar to 2016), but this dropped to 91% in 2018—primarily due to passive Level 1 customers switching from CPP to PTR.

[6] Active participants are those who have opted into a technology package above the default (e.g., opted into Levels 2, 3, or 4), or participants on the default technology package (Level 1) who have ever visited the WorcesterSmart web portal. The active/passive status of Level 1 customers for each year was determined as of the end of that year.

Table 3. Customer Enrollment by Technology Level and Price Plan: 2017-2018

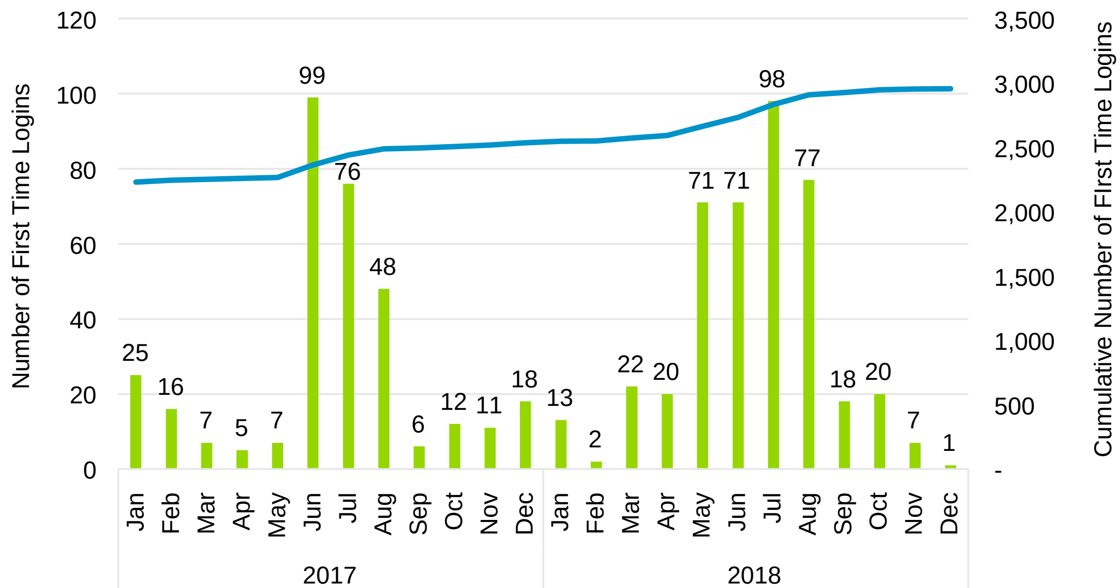
Level		Price Plan	Number of Residential Customers (2017)	Number of Residential Customers (2018)
1	Advanced metering infrastructure + web portal + mobile app	CPP – Active*	2,077	2,152
		CPP – Passive	8,784	7,659
		PTR – Active*	99	139
		PTR – Passive	389	883
2	Level 1 + digital picture frame	CPP	778	726
		PTR	36	71
3	Level 1 + smart thermostat	CPP	30	30
		PTR	3	4
4	Level 1 + Level 2 + Level 3 + load control devices	CPP	259	240
		PTR	17	20
	Total		**12,472**	**11,924**
	% Active*		**26%**	**28%**

* Active participants are those who have opted in to a technology package above the default (e.g., opted in to Levels 2, 3, or 4) or participants on the default technology package (Level 1) who have ever visited the WorcesterSmart web portal. The active/passive status of Level 1 customers for each year was determined as of the end of that year.

Source: Navigant analysis

Figure 10 shows the number of first time and cumulative logins to the WorcesterSmart web portal for each month of 2017 and 2018. Throughout the pilot, the highest frequency of initial logins to the portal was in June or July of each year, which is when Conservation Days ramped up each summer. This indicates that peak events piqued customers' interest in SES. Additionally, 420 customers logged in to the portal for the first time in 2018, suggesting that program messaging and peak events continued to drive engagement with the program.

Figure 10. Frequency of First Time Web Portal Logins by Month: 2017-2018

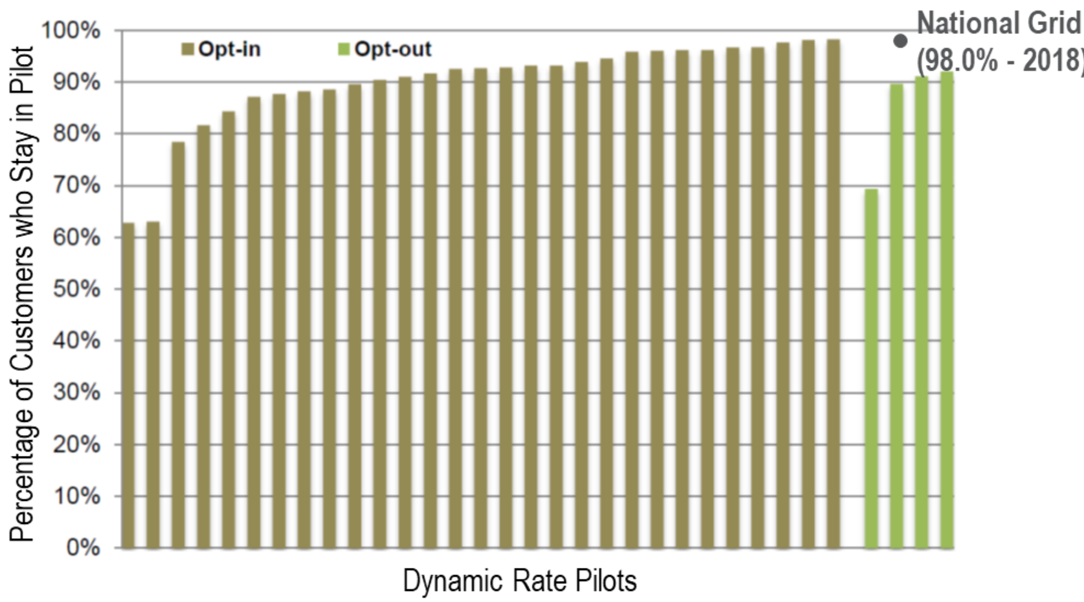


Note: Logins are shown for portal data received in December 2018, excluding logins from accounts not enrolled in the SES program.
Source: Navigant analysis

The retention rate in SES remained high throughout the pilot, staying at 98% at the end of 2018.[7] Most customers who opted out of the pilot did so at the beginning; the retention rate only dropped 0.4% from 2015 to 2018. Compared to 1-year customer retention rates in other utility dynamic rate pilots, National Grid had excellent customer retention, even after 4 years, as shown in Figure 11.[8]

[7] Over time, customer retention reflects how many customers remain in the pilot rather than dropping out. The retention rate considers only those customers who actually drop out of the pilot and excludes those who moved or switched to a competitive supplier, which could have happened for any number of reasons unrelated to the pilot.
[8] Figure 11 shows US Department of Energy Smart Grid Investment Grant (SGIG) dynamic rate pilot retention rates. Ten utilities undertook several pilot studies during the SGIG period and reported their experience in recruiting and retaining customers. Each bar in the chart represents a single treatment group within one of the utility pilots.

Figure 11. Customer Retention Rate Based on Whether the Utility Used Opt-In or Opt-Out Recruitment



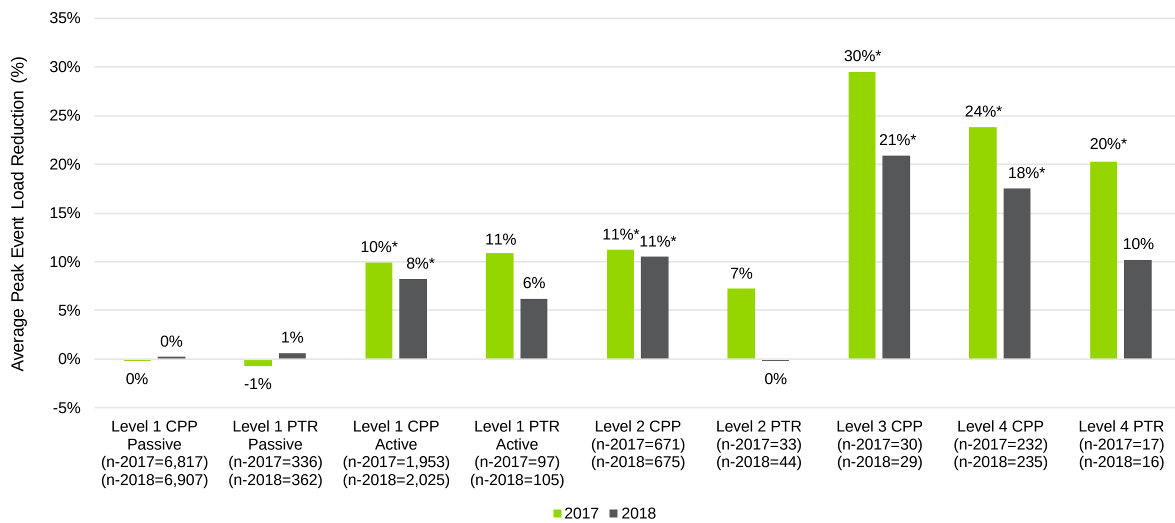
Sources: Lawrence Berkeley National Laboratory and Navigant analysis

Demand Impacts

In 2017 and 2018, active customers achieved average peak event load reductions of up to 30%, and in-home technology increased demand savings. Figure 12 shows the average percentage peak load reduction for each 2017 and 2018 event by technology/price groups.[9] Table 4 shows the absolute reductions. Whether on the CPP or PTR rate, customers achieved greater demand reductions with more advanced technology. The savings for CPP customers were statistically significant at the 90% confidence level for all active participants in both years. The savings for customers on the PTR rate were only statistically significant for Level 4 customers in 2017. The lack of statistical significance for the PTR rate was due to small sample sizes on that rate. At each technology level, active CPP customers conserved at least as much electricity as their PTR counterparts.

[9] As with the 2015 and 2016 analysis, Navigant did not analyze Level 3 PTR as this group only had three customers in 2017 and four in 2018.

Figure 12. Average Peak Event Load Reductions by Technology/Price Group: 2017-2018



Note: An asterisk (*) indicates that the majority of the event hours throughout the summer were statistically significant at the 90% confidence level for the indicated group. Additionally, n refers to the number of customers used in this particular analysis, not the total number of customers in each technology/price group.
Source: Navigant analysis

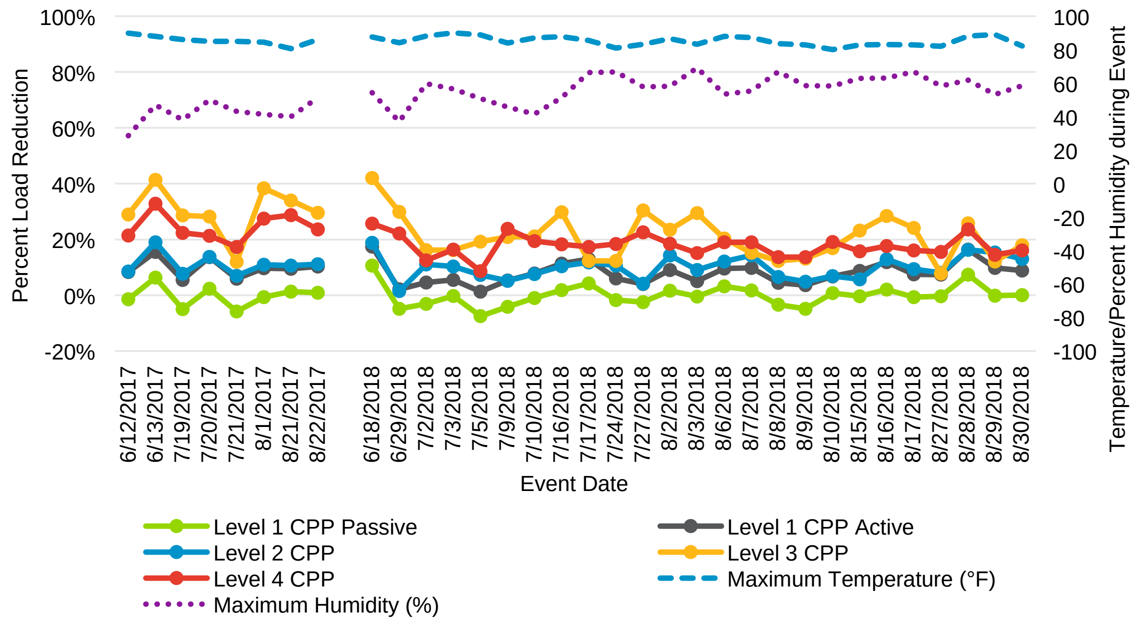
Table 4. Average Absolute Peak Event Load Reductions per Customer by Residential Technology/Price Group: 2017 and 2018

Technology/Price Group	2017 Absolute Savings (kW)	2018 Absolute Savings (kW)
Level 1 CPP Passive	0.00	0.00
Level 1 PTR Passive	-0.01	0.01
Level 1 CPP Active	0.11	0.09
Level 1 PTR Active	0.13	0.07
Level 2 CPP	0.13	0.12
Level 2 PTR	0.10	-0.01
Level 3 CPP	0.58	0.37
Level 4 CPP	0.52	0.36
Level 4 PTR	0.49	0.24

Source: Navigant analysis

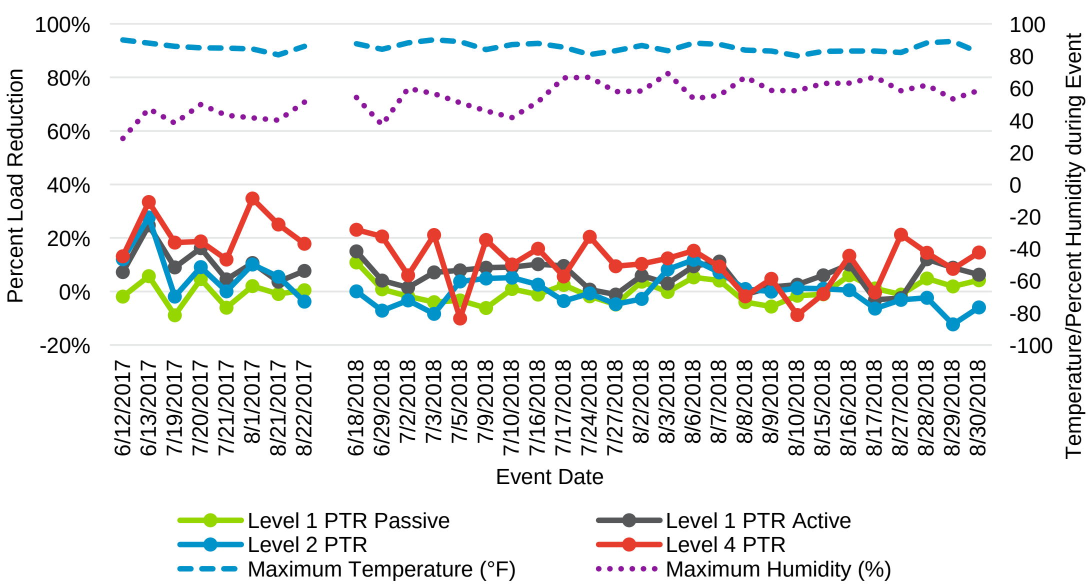
Figure 13 shows the average percentage impact for each event for the five residential CPP customer groups, and Figure 14 shows the average percentage impact for each event for the four residential PTR groups. For CPP customers, impacts were relatively flat throughout 2017 and were highest for the first event and then flat in 2018. For PTR customers, impacts were relatively flat in each of the two summers.

Figure 13. Percentage Savings for CPP Customers: 2017-2018



Source: Navigant analysis

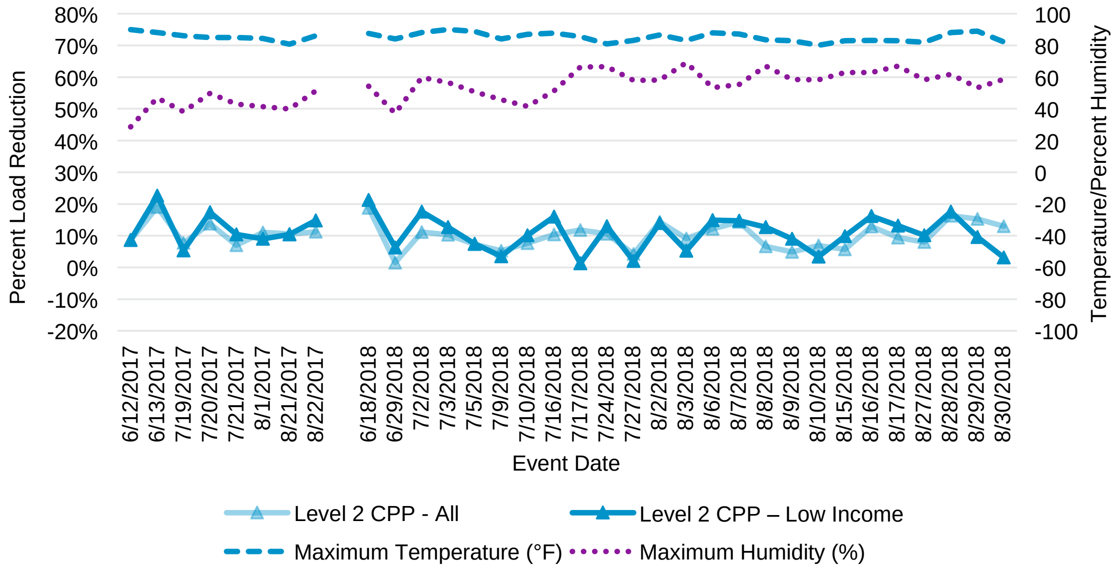
Figure 14. Percentage Savings for PTR Customers: 2017-2018



Source: Navigant analysis

Figure 15 shows the average percentage impact for each event for low income customers and all customers in Level 2 CPP. In 2015 and 2016, this group had lower impacts for low income customers; however, this gap closed in 2017 and 2018 when there was no difference between low and regular income customers.

Figure 15. Event Savings for Low Income Customers Compared to All Customers in Level 2 CPP: 2017-2018



Source: Navigant analysis

In the 2015/16 report, Navigant offered four hypotheses for why impacts for low income customers might diverge from regular income customers:

1. Central air conditioning penetration may be lower among low income customers.
2. Low income customers may have less discretionary energy usage and thus less energy to save.
3. Low income customers may have been less able to shift their usage than other residential customers.
4. The finding may be an anomaly, given that two of the three technology/price groups for which low income customers were analyzed did not show statistically significant differences.

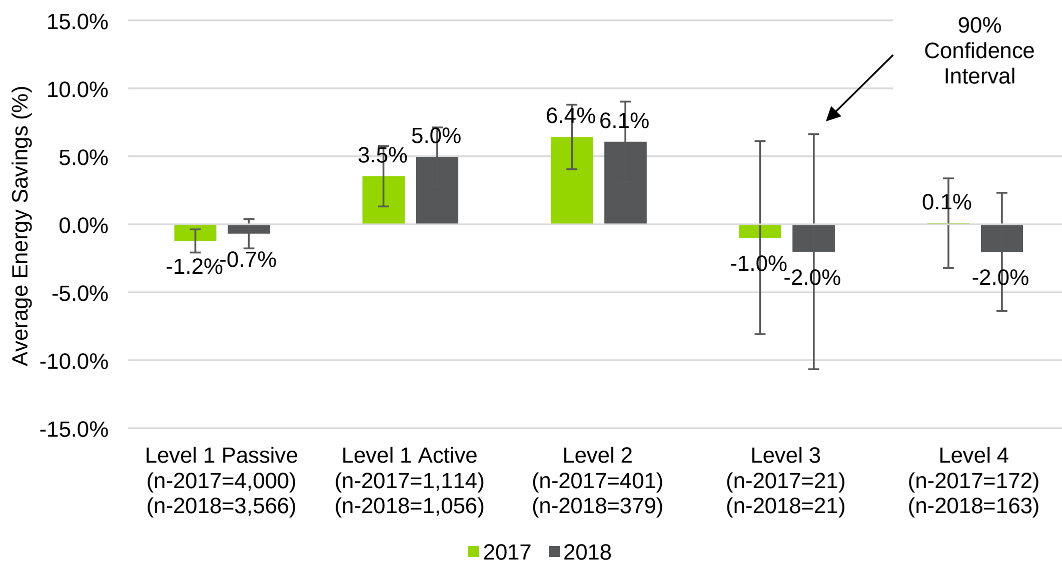
The first and third hypotheses do not mesh with Navigant's finding that the savings are now the same across income groups. The second hypothesis is still a possibility if regular income customers lowered their impacts more than low income customers between 2015/2016 and 2017/2018. The fourth hypothesis of an anomaly is also still a possibility.

Energy Impacts

Figure 16 shows the average percentage energy impacts with 90% confidence intervals for CPP customers in different technology levels in 2017 and 2018. In both years, energy savings for active participants were highest for Level 2 customers (40 kWh per month in 2017, 39 kWh per month in 2018), followed by Level 1 Active customers (20 kWh per month in 2017, 29 kWh per month in 2018). Although the point estimates of energy savings for Level 1 Passive, Level 3, and Level 4 customers changed between 2017 and 2018, the changes were not statistically significant; this indicates the energy savings were similar across the 2 years and not statistically different from zero.

Active participants averaged 3.9% energy savings in 2017 and 4.6% in 2018. The program's target of 5% energy savings for active participants was within the 90% confidence bounds of these estimates.

Figure 16. Average Energy Impacts for CPP Customers by Technology Level: 2017-2018



Note: n refers to the number of customers used in this particular analysis, not the total number of customers in each technology/price group.
Source: Navigant analysis

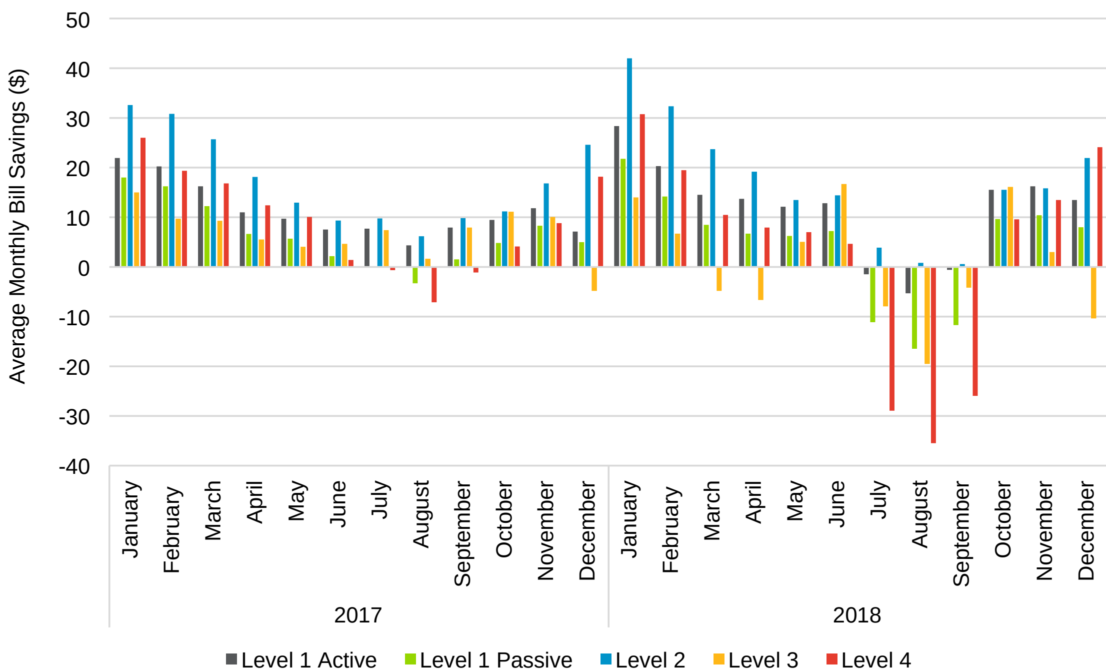
Bill Impacts

CPP customers averaged $177 in total bill savings for 2017-2018. For the CPP rate, average per-customer bill savings for 2017-2018 totaled $411 for Level 2, $274 for active customers in Level 1, $145 for Level 4, $130 for passive customers in Level 1, and $90 for Level 3.

Figure 17 shows the average bill savings by month and year for CPP customers in 2017 and 2018. The month of each bill was defined as the last day of the billing period. This means that, on average, bills in each month contain an equal number of days in the current month and the previous month—for example, bills in May reflect usage in the second half of April and the first half of May. On average, across technologies, bill savings were highest in January 2018, which reflects December 2017 and January 2018 usage.

Unless there was a peak event, customers saved money on the TOU rate because the TOU rate was lower than the basic rate for non-peak event hours. Customer bills went up in July, August, and September of 2018, reflecting usage in June, July, August, and September. These bill increases were expected, since July and August were when the majority of the peak events were called in 2018. The bill increases in these months were slightly larger than the bill increases in the summers of 2015 and 2016 due to the increase in total event hours in 2018. In 2017, there were only eight peak events called so most groups did not experience bill increases in the summer months.

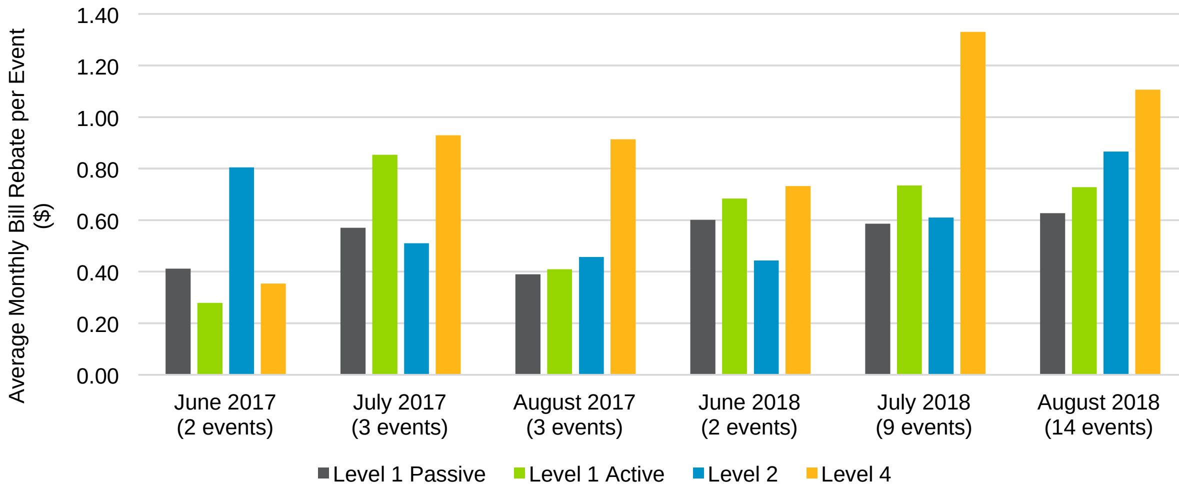
Figure 17. 2017-2018 Average Bill Savings for CPP Customers: 2017-2018



Source: Navigant analysis

PTR customers averaged approximately $24 in total bill rebates in 2017 and 2018. The bill savings for PTR customers came from the monthly rebate earned during peak events based on the payments made by National Grid. Figure 18 shows the average bill rebates per event by month and year for PTR customers. In 2017 and 2018, Level 4 customers achieved the highest average rebate of $1.07 per event; Level 2 customers averaged $0.70 per event, active Level 1 customers averaged $0.68 per event, and passive Level 1 customers averaged $0.57 per event.

Figure 18. Average Bill Rebates for PTR Customers: 2017-2018



Source: Navigant analysis

Table 5 shows savings for CPP and PTR customers in 2017 and 2018 by the peak event hours that were actually called (52 in 2017 and 175 in 2018) and if the maximum peak event hours (175) had been called. In 2017, when fewer than 175 peak event hours were called, the estimated bill savings with 175 peak event hours were based on the average savings per event hour. Generally, if 175 peak event hours had been called:

- PTR customers would have earned more savings in rebates.
- CPP customers would have had slightly lower bill savings, as their bills would increase due to more hours being charged at the higher peak event period rate.

Table 5. Bill Savings by Price Plan: 2017-2018

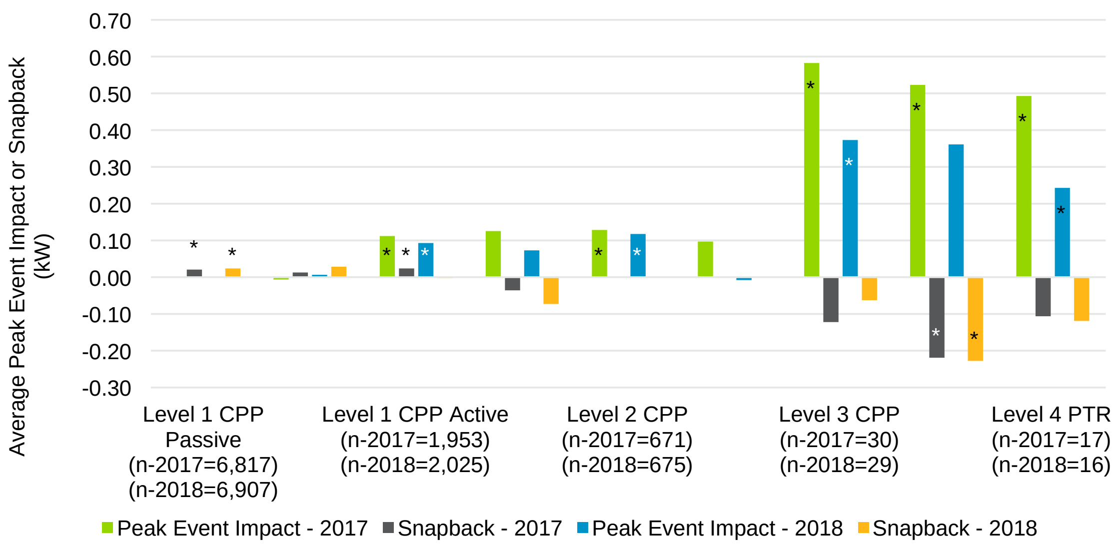
Price Plan	2017 With 52 Peak Event Hours	2017 With 175 Peak Event Hours	2018 With 175 Peak Event Hours
CPP	$122	$109	$88
PTR	$9	$30	$20

Source: Navigant analysis

Load Shifting Impacts

Figure 19 shows the average peak event impact and snapback for each residential technology/price group in 2017 and 2018. The blue and green bars show the average event impacts for 2017 and 2018 respectively. The grey and orange bars show the average snapback impact for 2017 and 2018 respectively. Negative snapback values indicate an increase in usage in the hours immediately following a peak event. The overall result is that snapback was not very prominent. Similar to 2015 and 2016, Level 1 and 2 customers in both price groups experienced hardly any snapback, while Level 3 and 4 customers did have some. The disparity in snapback across the different technology levels was almost certainly driven by smart thermostats—Level 3 and 4 customers had them, but Level 1 and 2 customers did not. National Grid adjusted the smart thermostats remotely during peak event hours and then returned them to the user-defined temperature once the peak event ended. The snapback observed for customers with these thermostats was likely from the HVAC system working hard to cool the home after running less than usual during peak event hours. Even for Level 3 and 4 customers where significant snapback was observed, it was relatively small in magnitude and short in length. For Level 3 and 4 customers, on average, the snapback was less than half the magnitude of the peak event impact. Additionally, snapback generally lasted less than 2 hours, which is fairly short given the long length of the peak events.

Figure 19. Snapback Compared to Peak Event Impacts: 2017-2018



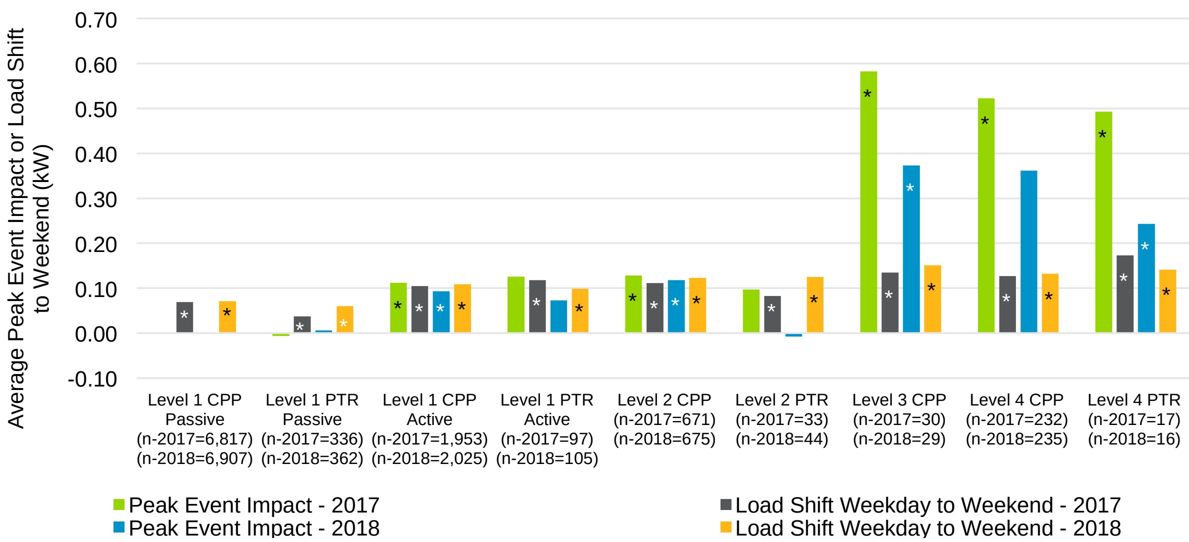
Note: Negative values for snapback in this graph indicate an increase in usage in the hours after peak events. An asterisk (*) indicates that the majority of the event or snapback hours throughout the summer were statistically significant for the indicated group. Also, n refers to the number of customers used in this particular analysis, not the total number of customers in each technology/price group.

Source: Navigant analysis

Figure 20 shows the average peak event impact and the average shift of usage from weekdays to weekends for each residential technology/price group in each summer (June to September) of 2017 and 2018.[10] Navigant observed some load shifting to weekends for each technology/price level, and the magnitude was similar across the 2 years.

[10] CPP customers had an incentive to shift their usage from weekdays to weekends to avoid paying the higher peak time rate that ran from 8 a.m. to 8 p.m. on weekdays. PTR customers may have had an incentive to shift usage to weekends when peak events were being run during the week, but the incentive was much smaller because they were not charged the TOU rate. Additionally, the pilot may have caused them to form habits that involved shifting their energy-intensive activities to times when peak events would not be called.

Figure 20. Weekday to Weekend Load Shifting Compared to Peak Event Impacts: 2017-2018



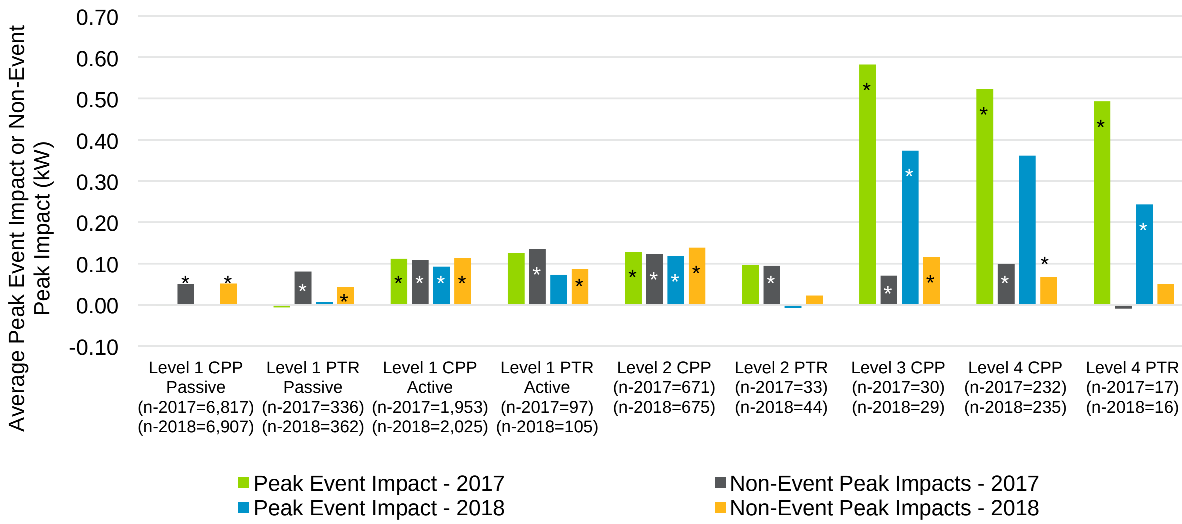
Note: Positive numbers for load shift in this graph indicate a decrease in weekday usage and an increase in weekend usage. An asterisk (*) indicates that the majority of the hours throughout the summer were statistically significant for the indicated group. Also, n refers to the number of customers used in this particular analysis, not the total number of customers in each technology/price group.

Source: Navigant analysis

Figure 21 shows the average peak event impacts and the average non-event peak impacts for each residential technology/price group in 2017 and 2018.[11] The blue and green bars show the average event impacts for 2017 and 2018 respectively. The grey and orange bars show the average non-event peak impact for 2017 and 2018 respectively. Positive non-event peak impact values indicate customers are shifting usage away from the peak periods (8 a.m. to 8 p.m. on non-holiday weekdays) even outside of peak events. Almost every technology/price group had non-event peak impacts in both years. The effect was of a similar magnitude for most groups across the 2 years. The magnitudes were typically less than the peak event impacts. In particular, for the three groups with smart thermostats, the magnitude of the non-event peak impacts was small compared to the peak event impacts.

[11] CPP customers had an incentive to shift their usage from peak hours to off-peak hours, even in the absence of a Conservation Day, because electricity was cheaper for them during off-peak (8 p.m. to 8 a.m.) hours. PTR customers had no monetary incentive to shift usage to off-peak hours on days that were not Conservation Days, but the pilot may have caused them to form habits that involved shifting their energy-intensive activities to times when peak events would not be called.

Figure 21. Non-Event Peak Impacts Compared to Peak Event Impacts



Note: Positive numbers for non-event peak impacts indicate savings during peak hours that were not also peak events. An asterisk (*) indicates that the majority of the event hours throughout the summer were statistically significant for the indicated group. Also, n refers to the number of customers used in this particular analysis, not the total number of customers in each technology/price group.

Source: Navigant analysis

Appendix A: SES Pricing Rates

The pilot pricing and basic rates for the entire pilot are shown in Table 6.

Table 6. SES Pricing Rates: 2015-2018

Effective for Usage During	Rate (cents / kWh)				
	Smart Rewards Pricing*			Conservation Day Rebate*	Basic Rate***
	Peak Period**	Off-Peak Period**	Peak Event Period		
Nov 2018 – Dec 2018	13.100	10.697	66.997	(66.997)	13.718
May 2018 – Oct 2018	10.383	8.488	52.887	(52.887)	10.870
Nov 2017 – Apr 2018	12.108	9.912	61.373	(61.373)	12.673
May 2017 – Oct 2017	9.016	7.397	45.316	(45.316)	9.432
Nov 2016 – Apr 2017	9.369	7.742	45.853	(45.853)	9.787
Oct 2016	7.744	6.421	37.416	(37.416)	8.084
May 2016 – Sep 2016	7.702	6.379	37.374	(37.374)	8.042
Nov 2015 – Apr 2016	12.463	10.226	62.636	(62.636)	13.038
May 2015 – Oct 2015	8.859	7.313	43.544	(43.544)	9.257
Jan 2015 – Apr 2015	15.537	12.675	79.730	(79.730)	16.273

* Smart Rewards Pricing is referred to as CPP and Conservation Day rebate as PTR in Navigant's reporting.

**The peak period is non-peak event periods from 8 a.m. to 8 p.m. on non-holiday, weekdays. The off-peak period is any time that is not peak period or peak events; this includes all weekend, evening, and holiday hours.

***Basic rates apply to customers not enrolled in the SES program.

Source: National Grid

Appendix B: Additional Impact Assessment Results – Demand Impacts

Absolute and percentage impacts by technology/price group for each peak event in all four summers of the pilot are shown in Table 7 through Table 14. Positive values indicate savings, or a decrease in electricity usage, and negative values indicate dissaving, or an increase in electricity usage.

Table 7. Percentage Demand Impact for Peak Events by Technology/Price Group: 2015

Event Date	Level 1 CPP Passive	Level 1 CPP Active	Level 1 PTR Passive	Level 1 PTR Active	Level 2 CPP	Level 2 PTR	Level 3 CPP	Level 4 CPP	Level 4 PTR
June 23	9% *	21% *	9% *	23% *	27% *	20%	50% *	48% *	31% *
July 8	-1%	15% *	0%	15%	21% *	3%	49% *	38% *	40% *
July 13	8% *	19% *	3%	20% *	23% *	16%	40% *	40% *	29% *
July 20	0%	13% *	4%	11%	20% *	8%	45% *	34% *	49% *
July 21	-3% *	12% *	2%	16% *	21% *	-2%	26% *	26% *	27% *
July 28	4% *	16% *	12% *	14%	22% *	16%	35% *	35% *	33% *
July 29	-3% *	9% *	5%	9%	18% *	-6%	29% *	28% *	10%
July 30	2% *	12% *	6%	16% *	19% *	8%	26% *	34% *	26% *
July 31	-4% *	5%	0%	8%	12% *	5%	32% *	29% *	-9%
August 3	3% *	14% *	4%	6%	16% *	2%	33% *	33% *	21%
August 4	3% *	13% *	-1%	3%	14% *	18%	28%	25% *	8%
August 17	4% *	14% *	4%	14% *	23% *	15%	33% *	31% *	20%
August 18	4% *	14% *	2%	10%	16% *	17%	29% *	30% *	30% *
August 19	-1%	8% *	1%	4%	13% *	-2%	20%	17% *	14%
August 20	-1%	9% *	-2%	8%	15% *	10%	23%	27% *	32% *
August 31	2% *	11% *	6%	7%	14% *	14%	37% *	31% *	22%
September 1	0%	11% *	3%	11%	17% *	17%	25%	23% *	28% *
September 2	-4% *	6% *	-5%	1%	14% *	7%	25% *	20% *	14%
September 8	-1%	10% *	-7%	5%	15% *	17%	21% *	25% *	13%
September 9	-1%	5% *	-3%	-2%	10% *	6%	16%	12% *	6%
Average	**1%**	**12% ***	**2%**	**10%**	**17% ***	**9%**	**31% ***	**29% ***	**22%**

Note: An asterisk (*) indicates that the majority of the event hours were statistically significant at the 90% confidence level for the indicated group.

Source: Navigant analysis

Table 8. Percentage Demand Impact for Peak Events by Technology/Price Group: 2016

Event Date	Level 1 CPP Passive	Level 1 CPP Active	Level 1 PTR Passive	Level 1 PTR Active	Level 2 CPP	Level 2 PTR	Level 3 CPP	Level 4 CPP	Level 4 PTR
July 6	6% *	17% *	11% *	3%	23% *	15%	25% *	33% *	46% *
July 7	6% *	14% *	12% *	13%	23% *	-2%	26% *	34% *	28% *
July 13	5% *	18% *	-2%	10%	19% *	2%	21% *	34% *	29% *
July 14	7% *	15% *	8% *	8%	21% *	4%	40% *	37% *	38% *
July 15	2% *	13% *	0%	6%	16% *	2%	15%	28% *	23%
July 18	10% *	20% *	11% *	14% *	25% *	8%	26% *	30% *	38% *
July 22	7% *	20% *	8% *	16% *	20% *	10%	39% *	34% *	26% *
July 25	11% *	23% *	8% *	15% *	26% *	14%	29% *	31% *	21% *
July 26	-1%	13% *	-1%	5%	16% *	-6%	20% *	25% *	24% *
July 27	-3% *	10% *	-8% *	8%	13% *	12%	22% *	24% *	32% *
July 28	4% *	16% *	8% *	17% *	21% *	5%	15%	27% *	29% *
August 11	5% *	15% *	10% *	17% *	18% *	-7%	17% *	28% *	22% *
August 12	6% *	16% *	11% *	11% *	19% *	1%	20% *	29% *	12%
August 15	0%	12% *	1%	2%	13% *	0%	19% *	16% *	14%
August 16	3% *	12% *	1%	10%	15% *	9%	20%	27% *	18%
August 17	3% *	13% *	7%	8%	16% *	1%	35% *	31% *	44% *
August 18	-2% *	6% *	-2%	1%	7% *	-2%	26% *	18% *	19%
August 19	2% *	13% *	1%	-5%	10% *	-7%	43% *	31% *	25% *
August 26	3% *	14% *	4%	8%	14% *	2%	29% *	29% *	33% *
September 9	9% *	18% *	9% *	19% *	23% *	11%	32% *	36% *	34% *
Average	**4% ***	**15% ***	**5%**	**9%**	**18% ***	**3%**	**26% ***	**29% ***	**28% ***

Note: An asterisk (*) indicates that the majority of the event hours were statistically significant at the 90% confidence level for the indicated group.

Source: Navigant analysis

Table 9. Percentage Demand Impact for Peak Events by Technology/Price Group: 2017

Event Date	Level 1 CPP Passive		Level 1 CPP Active		Level 1 PTR Passive		Level 1 PTR Active		Level 2 CPP		Level 2 PTR		Level 3 CPP		Level 4 CPP		Level 4 PTR	
June 12	-1%		8%	*	-2%		7%		9%	*	12%		29%	*	21%	*	13%	
June 13	6%	*	16%	*	6%	*	25%	*	19%	*	28%	*	41%	*	33%	*	33%	*
July 19	-5%	*	6%	*	-9%	*	9%		8%	*	-2%		29%	*	22%	*	18%	*
July 20	2%	*	14%	*	5%		16%	*	14%	*	9%		28%	*	21%	*	19%	*
July 21	-6%	*	6%	*	-6%		5%		7%	*	0%		12%		17%	*	12%	
August 1	-1%		10%	*	2%		11%		11%	*	10%		38%	*	28%	*	35%	*
August 21	1%		10%	*	-1%		4%		11%	*	6%		34%	*	29%	*	25%	*
August 22	1%		10%	*	1%		8%		11%	*	-4%		30%	*	24%	*	18%	
Average	**0%**		**10%**	*****	**-1%**		**11%**		**11%**	*****	**7%**		**30%**	*****	**24%**	*****	**20%**	*****

Note: An asterisk (*) indicates that the majority of the event hours were statistically significant at the 90% confidence level for the indicated group.

Source: Navigant analysis

Table 10. Percentage Demand Impact for Peak Events by Technology/Price Group: 2018

Event Date	Level 1 CPP Passive	Level 1 CPP Active	Level 1 PTR Passive	Level 1 PTR Active	Level 2 CPP	Level 2 PTR	Level 3 CPP	Level 4 CPP	Level 4 PTR
June 18	11% *	17% *	11% *	15% *	19% *	0%	42% *	26% *	23% *
June 29	-5% *	2%	1%	4%	2%	-7%	30% *	22% *	21% *
July 2	-3% *	5% *	-2%	2%	11% *	-3%	16% *	13% *	6%
July 3	0%	6% *	-4%	7%	10% *	-8%	16% *	16% *	21% *
July 5	-8% *	1%	-3%	8%	7% *	4%	19% *	9% *	-10%
July 9	-4% *	5% *	-6%	9%	5%	5%	21% *	24% *	19%
July 10	-1%	8% *	1%	9%	8% *	5%	21% *	19% *	10%
July 16	2% *	11% *	-1%	10%	10% *	3%	30% *	18% *	16%
July 17	4% *	13% *	2%	10%	12% *	-4%	12%	17% *	6%
July 24	-2% *	6% *	-2%	1%	11% *	-1%	12%	18% *	21%
July 27	-2% *	4% *	-5%	-1%	4%	-5%	30% *	23% *	9%
August 2	2% *	9% *	4%	6%	14% *	-3%	24% *	19% *	10%
August 3	0%	5% *	0%	3%	9% *	8%	30% *	15% *	12%
August 6	3% *	10% *	5% *	9%	12% *	12%	20% *	19% *	15%
August 7	2% *	10% *	4%	11% *	14% *	7%	15%	19% *	9%
August 8	-3% *	5% *	-4%	-1%	7% *	1%	12%	14% *	-2%
August 9	-5% *	4% *	-6%	2%	5%	0%	13%	14% *	5%
August 10	1%	7% *	-2%	3%	7% *	1%	17%	19% *	-9%
August 15	0%	9% *	-1%	6%	6% *	1%	23% *	16% *	-1%
August 16	2% *	12% *	6% *	10%	13% *	1%	28% *	18% *	13%
August 17	-1%	8% *	1%	-3%	9% *	-6%	24% *	16% *	0%
August 27	0%	7% *	-1%	-3%	8% *	-3%	8%	16% *	21% *
August 28	7% *	16% *	5%	12% *	16% *	-2%	26% *	24% *	15%
August 29	0%	10% *	2%	9%	15% *	-12%	12%	15% *	9%
August 30	0%	9% *	4%	6%	13% *	-6%	18%	16% *	15%
Average	**0%**	**8% ***	**1%**	**6%**	**11% ***	**0%**	**21% ***	**18% ***	**10%**

Note: An asterisk (*) indicates that the majority of the event hours were statistically significant at the 90% confidence level for the indicated group.

Source: Navigant analysis

Table 11. Absolute Demand Impact (kW) for Peak Events by Technology/Price Group: 2015

Event Date	Level 1 CPP Passive	Level 1 CPP Active	Level 1 PTR Passive	Level 1 PTR Active	Level 2 CPP	Level 2 PTR	Level 3 CPP	Level 4 CPP	Level 4 PTR
June 23	0.101 *	0.222 *	0.267 *	0.095 *	0.307 *	0.250	0.806 *	0.872 *	0.695 *
July 8	-0.009	0.150 *	0.173	0.002	0.213 *	0.032	0.740 *	0.662 *	0.838 *
July 13	0.086 *	0.193 *	0.226	0.034 *	0.236 *	0.185	0.609 *	0.712 *	0.561 *
July 20	0.003	0.157 *	0.159	0.049	0.244 *	0.102	0.886 *	0.694 *	1.396 *
July 21	-0.034 *	0.135 *	0.193	0.021 *	0.232 *	-0.026	0.426 *	0.472 *	0.581 *
July 28	0.050 *	0.184 *	0.168 *	0.133	0.264 *	0.225	0.720 *	0.712 *	0.805 *
July 29	-0.037 *	0.102 *	0.104	0.052	0.208 *	-0.071	0.539 *	0.611 *	0.243
July 30	0.025 *	0.129 *	0.210	0.072 *	0.222 *	0.095	0.417 *	0.665 *	0.532 *
July 31	-0.040 *	0.043	0.083	-0.001	0.117 *	0.050	0.432 *	0.474 *	-0.142
August 3	0.035 *	0.147 *	0.072	0.044	0.178 *	0.026	0.520 *	0.662 *	0.423
August 4	0.034 *	0.131 *	0.028	-0.006	0.141 *	0.224	0.388	0.407 *	0.131
August 17	0.054 *	0.164 *	0.193	0.043 *	0.295 *	0.198	0.686 *	0.691 *	0.445
August 18	0.049 *	0.173 *	0.130	0.028	0.210 *	0.261	0.571 *	0.687 *	0.769 *
August 19	-0.010	0.091 *	0.052	0.012	0.153 *	-0.028	0.341	0.325 *	0.300
August 20	-0.011	0.095 *	0.101	-0.015	0.165 *	0.124	0.370	0.462 *	0.662 *
August 31	0.023 *	0.124 *	0.093	0.071	0.160 *	0.180	0.650 *	0.621 *	0.416
September 1	0.000	0.105 *	0.109	0.027	0.169 *	0.237	0.341	0.372 *	0.530 *
September 2	-0.043 *	0.061 *	0.012	-0.051	0.153 *	0.093	0.400 *	0.373 *	0.304
September 8	-0.011	0.125 *	0.072	-0.079	0.178 *	0.261	0.419 *	0.559 *	0.292
September 9	-0.017	0.058 *	-0.025	-0.031	0.126 *	0.087	0.320	0.249 *	0.129
Average	**0.012**	**0.129 ***	**0.121**	**0.025**	**0.199 ***	**0.125**	**0.529 ***	**0.564 ***	**0.496**

Note: An asterisk (*) indicates that the majority of the event hours were statistically significant at the 90% confidence level for the indicated group.

Source: Navigant analysis

Table 12. Absolute Demand Impact (kW) for Peak Events by Technology/Price Group: 2016

Event Date	Level 1 CPP Passive	Level 1 CPP Active	Level 1 PTR Passive	Level 1 PTR Active	Level 2 CPP	Level 2 PTR	Level 3 CPP	Level 4 CPP	Level 4 PTR
July 6	0.076 *	0.213 *	0.146 *	0.036	0.278 *	0.226	0.544 *	0.773 *	1.146 *
July 7	0.069 *	0.144 *	0.137 *	0.151	0.239 *	-0.028	0.402 *	0.574 *	0.500 *
July 13	0.052 *	0.191 *	-0.018	0.114	0.194 *	0.022	0.362 *	0.639 *	0.576 *
July 14	0.071 *	0.151 *	0.093 *	0.095	0.231 *	0.053	0.617 *	0.628 *	0.694 *
July 15	0.026 *	0.145 *	0.001	0.075	0.175 *	0.024	0.285	0.564 *	0.486
July 18	0.135 *	0.244 *	0.149 *	0.186 *	0.317 *	0.116	0.531 *	0.646 *	0.865 *
July 22	0.095 *	0.269 *	0.116 *	0.236 *	0.257 *	0.149	0.947 *	0.871 *	0.686 *
July 25	0.163 *	0.310 *	0.123 *	0.227 *	0.347 *	0.225	0.679 *	0.758 *	0.541 *
July 26	-0.008	0.148 *	-0.009	0.062	0.182 *	-0.090	0.388 *	0.530 *	0.532 *
July 27	-0.039 *	0.120 *	-0.098 *	0.103	0.152 *	0.172	0.442 *	0.513 *	0.742 *
July 28	0.049 *	0.193 *	0.109 *	0.230 *	0.252 *	0.072	0.313	0.602 *	0.667 *
August 11	0.064 *	0.200 *	0.141 *	0.251 *	0.228 *	-0.113	0.410 *	0.696 *	0.577 *
August 12	0.085 *	0.208 *	0.167 *	0.167 *	0.252 *	0.022	0.457 *	0.697 *	0.293
August 15	0.003	0.126 *	0.017	0.027	0.148 *	-0.004	0.335 *	0.307 *	0.269
August 16	0.029 *	0.112 *	0.010	0.101	0.145 *	0.105	0.278	0.406 *	0.284
August 17	0.036 *	0.127 *	0.074 *	0.088	0.157 *	0.012	0.524 *	0.505 *	0.761 *
August 18	-0.024 *	0.061 *	-0.022	0.014	0.065 *	-0.030	0.419 *	0.322 *	0.360
August 19	0.02 *	0.134 *	0.013	-0.054	0.102 *	-0.092	0.745 *	0.574 *	0.502 *
August 26	0.032 *	0.148 *	0.050 *	0.097	0.152 *	0.029	0.534 *	0.586 *	0.696 *
September 9	0.105 *	0.206 *	0.107 *	0.236 *	0.269 *	0.164	0.629 *	0.762 *	0.740 *
Average	**0.052 ***	**0.173 ***	**0.065**	**0.122**	**0.207 ***	**0.052**	**0.492 ***	**0.598 ***	**0.596 ***

Note: An asterisk (*) indicates that the majority of the event hours were statistically significant at the 90% confidence level for the indicated group.

Source: Navigant analysis

Table 13. Absolute Demand Impact (kW) for Peak Events by Technology/Price Group: 2017

Event Date	Level 1 CPP Passive	Level 1 CPP Active	Level 1 PTR Passive	Level 1 PTR Active	Level 2 CPP	Level 2 PTR	Level 3 CPP	Level 4 CPP	Level 4 PTR
June 12	-0.017	0.095 *	-0.025	0.086	0.096 *	0.152	0.619 *	0.502 *	0.325
June 13	0.087 *	0.198 *	0.081	0.323 *	0.241 *	0.389 *	0.936 *	0.811 *	0.873 *
July 19	-0.062 *	0.065 *	-0.116 *	0.107	0.090 *	-0.025	0.577 *	0.505 *	0.438 *
July 20	0.031 *	0.167 *	0.064	0.204 *	0.171 *	0.125	0.582 *	0.488 *	0.456 *
July 21	-0.065 *	0.062 *	-0.074	0.049	0.075 *	0.001	0.213	0.342 *	0.254
August 1	-0.008	0.100 *	0.024	0.112	0.115 *	0.119	0.666 *	0.540 *	0.730 *
August 21	0.014	0.091 *	-0.010	0.035	0.106 *	0.063	0.506 *	0.492 *	0.464 *
August 22	0.011	0.119 *	0.007	0.090	0.133 *	-0.050	0.560 *	0.502 *	0.403
Average	**-0.001**	**0.112 ***	**-0.006**	**0.126**	**0.128 ***	**0.097**	**0.582 ***	**0.523 ***	**0.493 ***

Note: An asterisk (*) indicates that the majority of the event hours were statistically significant at the 90% confidence level for the indicated group.

Source: Navigant analysis

Table 14. Absolute Demand Impact (kW) for Peak Events by Technology/Price Group: 2018

Event Date	Level 1 CPP Passive		Level 1 CPP Active		Level 1 PTR Passive		Level 1 PTR Active		Level 2 CPP		Level 2 PTR	Level 3 CPP		Level 4 CPP		Level 4 PTR	
June 18	0.138	*	0.217	*	0.145	*	0.191	*	0.231	*	0.002	0.838	*	0.576	*	0.588	*
June 29	-0.050	*	0.022		0.008		0.044		0.014		-0.088	0.486	*	0.426	*	0.475	*
July 2	-0.043	*	0.063	*	-0.028		0.022		0.153	*	-0.053	0.340	*	0.294	*	0.160	
July 3	-0.003		0.075	*	-0.060		0.102		0.140	*	-0.131	0.355	*	0.399	*	0.576	*
July 5	-0.098	*	0.017		-0.047		0.107		0.092	*	0.056	0.366	*	0.186	*	-0.249	
July 9	-0.044	*	0.055	*	-0.069		0.095		0.052		0.059	0.332	*	0.448	*	0.430	
July 10	-0.012		0.088	*	0.011		0.107		0.085	*	0.068	0.385	*	0.406	*	0.242	
July 16	0.022	*	0.133	*	-0.015		0.123		0.118	*	0.035	0.549	*	0.383	*	0.384	
July 17	0.049	*	0.139	*	0.028		0.107		0.132	*	-0.046	0.180		0.296	*	0.112	
July 24	-0.019	*	0.064	*	-0.021		0.007		0.117	*	-0.009	0.181		0.322	*	0.428	
July 27	-0.026	*	0.042	*	-0.058		-0.012		0.043		-0.059	0.514	*	0.443	*	0.214	
August 2	0.020	*	0.110	*	0.049		0.076		0.174	*	-0.038	0.446	*	0.399	*	0.253	
August 3	-0.005		0.056	*	-0.003		0.035		0.103	*	0.108	0.484	*	0.286	*	0.272	
August 6	0.044	*	0.127	*	0.078	*	0.132		0.158	*	0.176	0.429	*	0.448	*	0.405	
August 7	0.022	*	0.123	*	0.058		0.152	*	0.181	*	0.102	0.298		0.418	*	0.231	
August 8	-0.041	*	0.052	*	-0.052		-0.014		0.078	*	0.013	0.214		0.273	*	-0.040	
August 9	-0.055	*	0.038	*	-0.067		0.020		0.052		-0.001	0.213		0.257	*	0.103	
August 10	0.008		0.068	*	-0.018		0.028		0.069	*	0.014	0.249		0.332	*	-0.181	
August 15	-0.004		0.095	*	-0.012		0.068		0.062	*	0.014	0.375	*	0.300	*	-0.020	
August 16	0.025	*	0.134	*	0.076	*	0.120		0.145	*	0.007	0.486	*	0.345	*	0.304	
August 17	-0.008		0.079	*	0.014		-0.034		0.100	*	-0.081	0.374	*	0.292	*	-0.009	
August 27	-0.003		0.080	*	-0.013		-0.028		0.087	*	-0.040	0.126		0.296	*	0.472	*
August 28	0.102	*	0.218	*	0.070		0.167	*	0.211	*	-0.035	0.567	*	0.573	*	0.395	
August 29	-0.001		0.131	*	0.029		0.129		0.207	*	-0.190	0.256		0.340	*	0.224	
August 30	0.001		0.097	*	0.052		0.073		0.142	*	-0.075	0.292		0.294	*	0.309	
Average	**0.001**		**0.093**	*****	**0.006**		**0.073**		**0.118**	*****	**-0.008**	**0.373**	*****	**0.361**	*****	**0.243**	

Note: An asterisk (*) indicates that the majority of the event hours were statistically significant at the 90% confidence level for the indicated group.

Source: Navigant analysis

Appendix C: Additional Impact Assessment Results – Energy Impacts

Absolute and percentage annual energy impacts by technology level for CPP customers in all four years of the pilot are shown in Table 15 through Table 18. Positive values indicate savings, or a decrease in electricity usage, and negative values indicate dissaving, or an increase in electricity usage. Subtotals for all active customers and totals for all customers are also shown.

Table 15: Absolute and Percentage Annual Energy Impact by Technology Group for CPP Customers: 2015

	Per-Customer Energy Savings† (kWh)		Total Energy Savings† (MWh)		% Energy Savings†	
Level 1 Active	291.9	*	352.6	*	3.9%	*
Level 2	513.7	*	291.8	*	6.2%	*
Level 3	463.2		12.5		5.8%	
Level 4	155.2		36.8		1.8%	
All Active Customers	**340.0**		**693.7**		**4.3%**	
Level 1 Passive	-57.3		-478.8		-0.8%	
All Customers	**20.7**		**214.8**		**0.2%**	

* An asterisk indicates group level energy savings are statistically significantly different from zero at the 90% confidence level.
† Negative energy savings values indicate increased energy consumption.
Source: Navigant analysis

Table 16: Absolute and Percentage Annual Energy Impact by Technology Group for CPP Customers: 2016

	Per-Customer Energy Savings† (kWh)		Total Energy Savings† (MWh)		% Energy Savings†	
Level 1 Active	467.7	*	749.2	*	6.4%	*
Level 2	659.7	*	426.1	*	8.1%	*
Level 3	124.3		3.5		1.5%	
Level 4	131.4		31.8		1.5%	
All Active Customers	**480.8**		**1210.6**		**6.3%**	
Level 1 Passive	45.9		362.4		0.6%	
All Customers	**151.1**		**1573.0**		**2.0%**	

* An asterisk indicates group level energy savings are statistically significantly different from zero at the 90% confidence level.
† Negative energy savings values indicate increased energy consumption.
Source: Navigant analysis

Table 17: Absolute and Percentage Annual Energy Impact by Technology Group for CPP Customers: 2017

	Per-Customer Energy Savings† (kWh)		Total Energy Savings† (MWh)		% Energy Savings†	
Level 1 Active	234.8	*	487.6	*	3.5%	*
Level 2	477.5	*	371.5	*	6.4%	*
Level 3	-66.3		-2.0		-1.0%	
Level 4	6.6		1.7		0.1%	
All Active Customers	**273.2**		**858.8**		**3.9%**	
Level 1 Passive	-81.1		-712.6		-1.2%	
All Customers	**12.3**		**146.2**		**0.1%**	

* An asterisk indicates group level energy savings are statistically significantly different from zero at the 90% confidence level.
† Negative energy savings values indicate increased energy consumption.
Source: Navigant analysis

Table 18: Absolute and Percentage Annual Energy Impact by Technology Group for CPP Customers: 2018

	Per-Customer Energy Savings† (kWh)		Total Energy Savings† (MWh)		% Energy Savings†	
Level 1 Active	349.2	*	751.5	*	5.0%	*
Level 2	465.7	*	338.1	*	6.1%	*
Level 3	-146.2		-4.4		-2.0%	
Level 4	-167.0		-40.1		-2.0%	
All Active Customers	**332.0**		**1045.2**		**4.6%**	
Level 1 Passive	-45.6		-349.6		-0.7%	
All Customers	**64.4**		**695.6**		**0.9%**	

* An asterisk indicates group level energy savings are statistically significantly different from zero at the 90% confidence level.
† Negative energy savings values indicate increased energy consumption.
Source: Navigant analysis

10.9. Clifton Park Demonstration Summary

The latest quarterly report from the Clifton Park Demonstration is provided in a separate appendix document.

Appendix 10.9
Clinton Park Summary

Demand Reduction
REV Demonstration Project
in
Clifton Park

Q3 2020 Report

October 30, 2020

Table of Content

1.0 Executive Summary

On January 17, 2017 Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid" or the "Company") filed an implementation plan for the Demand Reduction REV Demonstration Project in Clifton Park (the "Project"), which is designed to provide residential customers in the Town of Clifton Park ("Clifton Park" or the "Town") with price signals, tools and information, enabled by infrastructure investments and distributed energy resources ("DER"), to reduce electric demand during peak times and inform the Reforming the Energy Vision ("REV") Proceeding.[1] The total number of customers affected (*i.e.,* those receiving a meter and those opting out) is approximately 14,400.

The Project aligns with the New York Public Service Commission's ("Commission") REV Track Two Order, wherein the Commission states that "[o]ne of the most important objectives of REV is improving overall system efficiency including the efficiency of capital investment to create value for customers. Toward that objective, electric peak reduction is among the most immediate priorities for REV implementation."[2] National Grid believes it is possible to create more responsive relationships with customers by leveraging infrastructure, customer outreach and engagement, deep energy insights, actionable information, price signals, DER products, and other services, to incentivize customers to reduce peak electric load and overall energy use. The Project includes the following elements:

- Infrastructure
    - Advanced Metering Infrastructure ("AMI")
    - Volt/VAR Optimization ("VVO"), including Conservation Voltage Reduction ("CVR")
- Customer Outreach & Engagement
- Deep Energy Insights & Actionable Information
- Price Signals
    - Peak Time Rewards ("PTR")
    - Voluntary Time-of-Use ("VTOU") Rate
- DER Services[3]

Key activities and milestones accomplished this quarter (Q3 2020) include:

Key Activity/Milestone	Outcome
Innovative Pricing	• Continued work to identify and design potential innovative pricing rate and test scenarios.
PTR	• Completed PTR Summer 2020.
Information Technology ("IT"), Advanced Analytics	• Advanced Analytics and Energy Forecasting team, as well as IT continued Project support.

[1] Case 14-M-0101, *Proceeding on Motion in Regard to Reforming the Energy Vision* ("REV Proceeding"), National Grid Demand Reduction REV Demonstration Project in Clifton Park Implementation Plan (filed January 17, 2017) ("Implementation Plan").
[2] REV Proceeding, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework ("REV Track Two Order") (issued May 19, 2016) at page 72.
[3] Part of the initial Project proposal included utility-supported Community Choice Aggregation ("CCA"); however, the Town decided not to pursue utility-supported CCA.

and Energy Forecasting efforts	
VVO efforts	• Began VVO data collection for Measurement and Verification ("M&V").
Customer Outreach & Marketing	• Updated Project communications to reflect Company's COVID-19 response and support. • Issued PTR Summer 2020 customer communications.
DER	• Awaiting outcome of innovative pricing demonstration proposal to understand impact on DER promotions.
COVID-19	• Implemented Business Continuity Plan. • Monitoring impacts on vendors, as well as customer load shapes; considering potential effects on innovative pricing proposal. • Adjusting protocols to ensure consistent and effective customer communications throughout the pandemic

Project Elements

A visual depiction of the Project's key services and offerings is provided below. Except for VVO, customers can opt in or opt out of each Project element. A description of each Project element is included with the individual sections of this quarterly report.

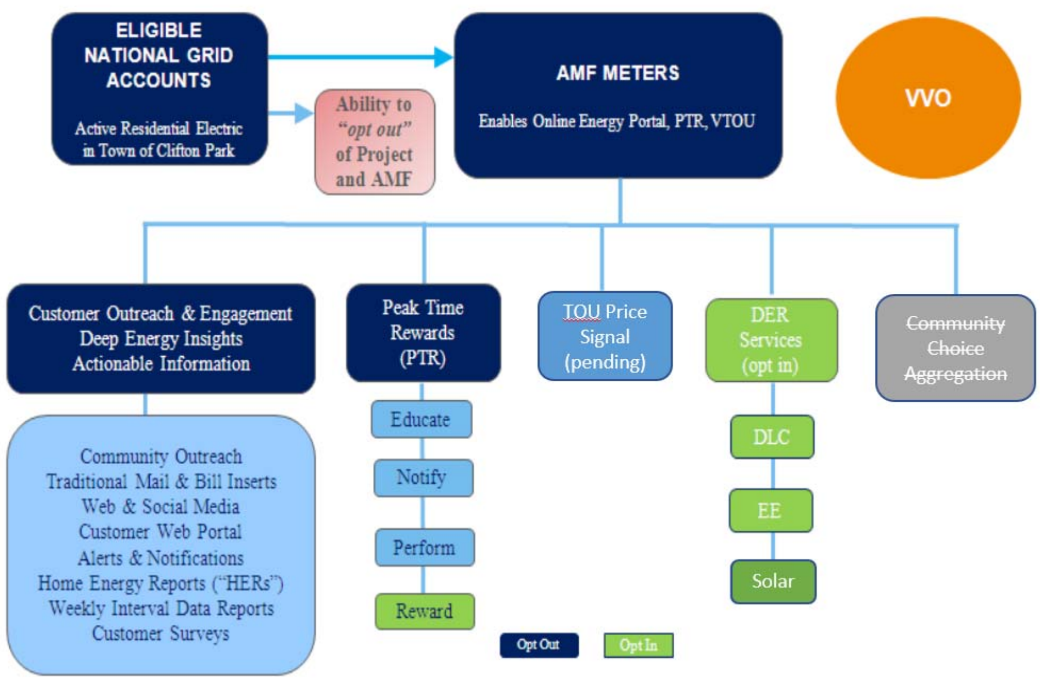


Figure 1: Project Elements

2.0 Highlights Since Previous Quarter

The following highlights key activities accomplished to date on the Project, as well as key activities planned for the next quarter.[4]

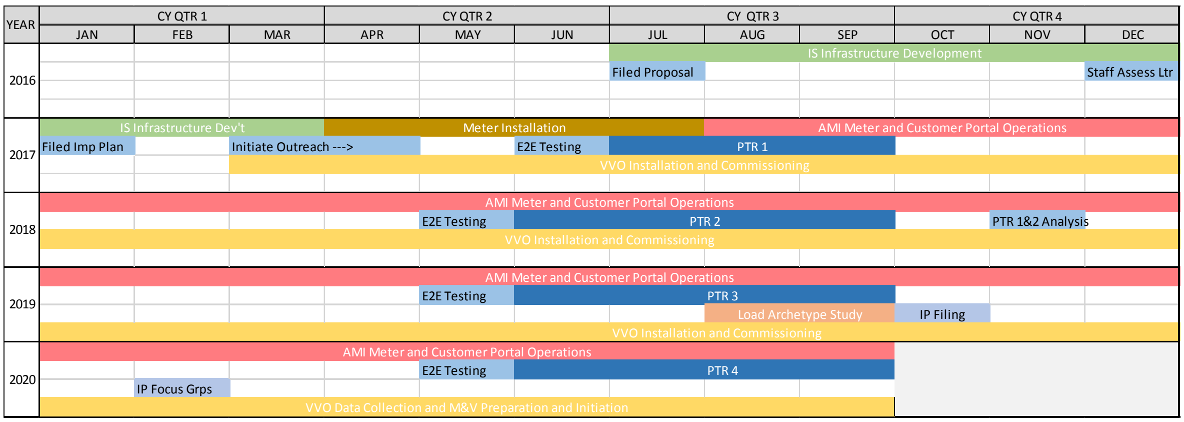


Figure 2: Work Plan Summary

2.1 Major Task Activities

2.1.1 Advanced Metering Infrastructure

AMI deployment in Clifton Park replaced existing National Grid electric and gas meter reading and billing processes for customers that have not opted out of the Project. AMI meters are read and select portions of data are transferred over a cellular network to National Grid for utility billing. Portions of data are also transferred to the Project's partners over secure networks to enable various elements of the Project, including the customer web portal. Interval data is used for PTR, customer billing, and to support authorized Project evaluation activities.

AMI deployment commenced at the end of the first quarter of 2017. Letters introducing Clifton Park customers to "Smart Energy Solutions," the customer-facing name of the Project, and postcards alerting customers of the AMI installation timeframe were distributed prior to installations. This allowed for a period during which customers could opt out of the AMI metering technology, as well as certain other aspects of the Project.

Customers choosing not to have AMI installed were directed to a specialized team at the National Grid Contact Center, who informed Customer Meter Services ("CMS") not to install AMI technology for those customers. Instead, the opt-out customers retained their existing meter (*i.e.*, automated

[4] The effects of the COVID-19 pandemic may impact the Project schedule. As those impacts become better understood, the Company will adjust the schedule accordingly.

meter reading ("AMR") meter or standard non-AMI meter). Additionally, during the Project term, customers may also have their AMI meter removed and replaced with an AMR meter at no additional cost.

The initial AMI opt-out rate was 8.8 percent, which equals approximately 1,256 premises. AMI meter opt-outs include customers who: 1) opted out through the National Grid Customer Contact Center; 2) informed CMS field workers in-person that they did not want the meter; or 3) were unable to provide access to the meter after three attempts by the Company without success.

National Grid continues to monitor AMI opt-outs throughout the term of the Project, as part of normal customer fluctuations in the Town (*e.g.*, new growth and customers moving). The National Grid Customer Contact Center is also accepting customer requests to install or remove the AMI technology and process orders.

2.1.1.1 Information Technology Activities

Timeframe	Completed Milestones
3rd Quarter 2020	• Continued Project support via National Grid's IT Support team. • Successfully migrated from dedicated Multiprotocol Label Switching ("MPLS") network to internet-based file transfer process, which aligns with vendor's cloud-based data center. The data center transition is anticipated late summer /early fall 2020.

2.1.1.2 Meter Installation Activities

Timeframe	Completed Milestones
3rd Quarter 2020	• Continued to support business practices related to move-in/out of customers.

2.1.2 Volt/VAR Optimization Device Installations

National Grid will enhance the efficiency of the electric system through the installation of software and devices that better regulate the voltage of the distribution system. These system enhancements will benefit all customers connected to those substations being upgraded. Working with the Project's VVO partner, Utilidata, National Grid started installing devices on the electric distribution system that monitor voltage along with advanced controllers for voltage regulators and reactive capacitors.

National Grid will evaluate the extent to which optimized regulation of the voltage and power factor of the electric distribution system benefits customers, ultimately reflected by improved feeder power factor, flatter voltage profiles, reduced feeder losses, reduced peak demand, and reduced energy consumption by customers. National Grid's targeted efficiency gain through the VVO portion of the Project is approximately three percent.

VVO installation scope includes:

- Three substation transformer load tap changers;
- Eleven feeders, including:
  - Twelve line voltage monitors;
  - Thirty-one advanced switching capacitors; and
  - Five pole-top regulators;
- A central controller and data concentrator installed at the National Grid Control Center;
- Supervisory control via National Grid's Supervisory Control and Data Acquisition ("SCADA") and Energy Management System ("EMS"); and
- Cellular connectivity between all field, substation devices, and the data concentrator.

The VVO equipment is installed and commissioned. The Company also worked with Utilidata to resolve system instability created by consecutive tap failures by increasing polling intervals. The Company began M&V work in June, after it completed site-acceptance testing.

Timeframe	Completed Milestones
3rd Quarter 2020	• Data collected for M&V is currently being analyzed by 3rd party.

2.1.3 Customer Outreach

National Grid has engaged residents of the Clifton Park community to learn about the Project and solicit input. The strategies include:

- Community outreach;
- Mail and bill inserts; and
- Web and social media.

Community Outreach

The National Grid marketing team performed studies of Clifton Park residential customers to assess areas of concern and to present recommendations. The studies were conducted by Market Probe moderators, a third-party market research group, via:

- Outreach sessions with Clifton Park residents in June 2018;
- Phone and online annual surveys; and
- Testimonial campaign with radio and billboard outreach launched in 2018.

Mail and Bill Inserts

Prior to the installation of AMI, National Grid delivered a set of communications via standard mailings to introduce Clifton Park customers to the Project and notify them of the imminent AMI technology. Customers were asked to contact National Grid if they did not want to receive a new AMI meter. Each letter spoke to the benefits of the Project and touched upon key Project elements available immediately and in the near future. The Company sent the communications as direct mail and bill inserts.

Thereafter, National Grid also sent a series of meter installation notifications letting customers know when the new meters would be installed. Included in the communications was an invitation to attend one of the Company's customer outreach and education meetings to learn more about the Project, ask questions, and interact with the National Grid team.

Following AMI meter installation, customers received educational materials focused on the various Project elements, such as enrolling in PTR. Bill inserts will continue to be incorporated four (4) times per year as Project elements are developed and implemented. The Company will also provide ongoing Project updates throughout the year using local media. Additionally, the Company created video tutorials that are posted on the National Grid website.

Web and Social Media

National Grid continues to expand the existing Clifton Park micro-site (https://www.nationalgridus.com/Upstate-NY-Home/Energy-Saving-Programs/Clifton-Park), a component of the Company's website (http://www.nationalgrid.com), to include information on the Project for Clifton Park residents.

The Project website includes the following information:

- Frequently Asked Questions video overview of the Project;
- Frequently Asked Questions pdf;
- Information about PTR;
- DER product and service options available (*e.g.*, New York Solar Marketplace); and
- Updates throughout the year to announce the rollout of new products and services.

National Grid also proactively reviews publicly available social media information to join conversations regarding the Project and to help answer questions

The Company also tracks customer interaction with the Opower web portal as part of the Project. Emails, bill inserts, direct mailings, and social media contributed to raising awareness of the information available to customers, as evidenced by increasing levels of customer interaction throughout the PTR seasons. Customer outreach activities continue outside of the PTR season to encourage ongoing customer engagement.

Areas of the portal experiencing common customer interaction include:

- My Energy Use;
- Ways to Save;
- Compare My Bills;
- Dashboard; and
- Home Energy Audit.

The Company also created the following key performance indicators to track and measure the success of Customer Outreach:

- Customer Acceptance of AMI Technology;
- Awareness;
- Customer Control of Energy Usage;
- Customer Satisfaction with National Grid; and

- Portal Engagement (*e.g.,* login creation, enrollment in PTR, and profile completion).

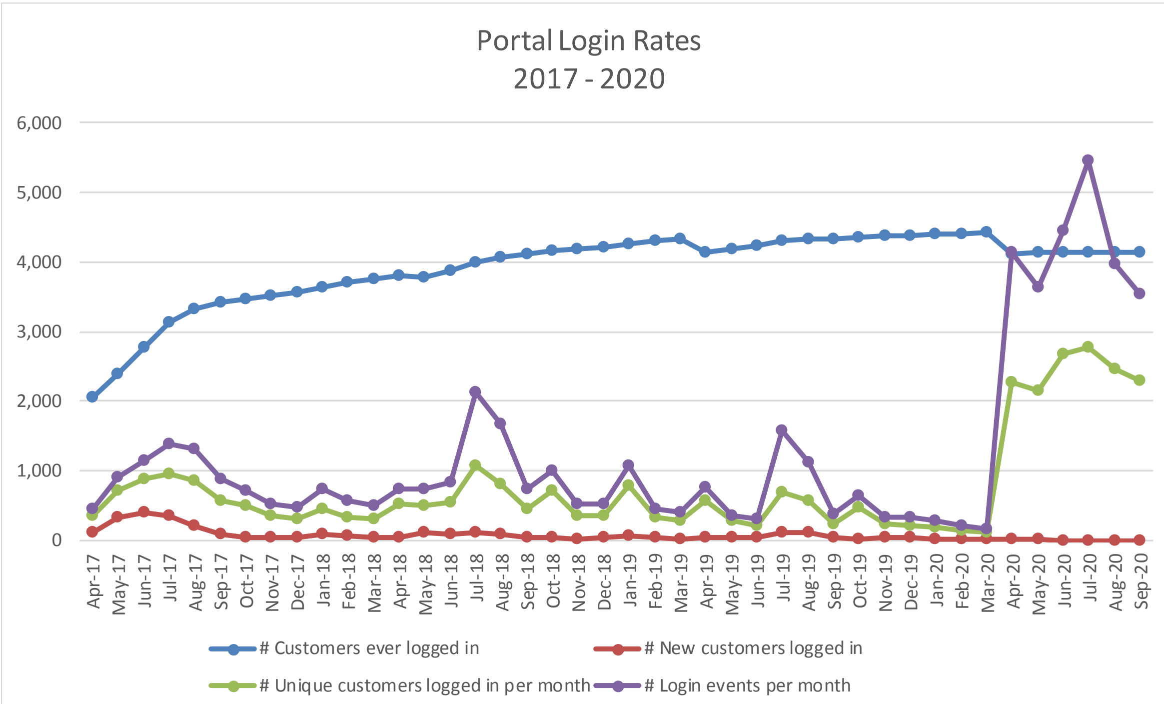


Figure 3: Portal Activity

Note: The Company recently learned that data collection methods to report Unique Logins Per Month (green) and Login Events Per Month (purple) were not identifying all web traffic for Clifton Park customers. The data have been updated for April 2020 to present. Future reports will include updated data for prior project years.

Timeframe	Completed Milestones
3rd Quarter 2020	• PTR pre-season letter deployed announcing start of PTR season 4.
	• Project communications updated with COVID-19 related language acknowledging customers may be home more using more energy.
	• Continued research on best practices for innovative pricing customer communications.

COVID-19 Related Communications

Project communications have been updated to acknowledge residential customers are likely spending more time at home and that is impacting their energy use.

2.1.4 Peak Time Rewards

National Grid seeks to incentivize Clifton Park customers to reduce electric use during specified peak times. Participating customers are rewarded for curtailing electric load through behavioral actions such as turning off lights, adjusting thermostats or using customer-controlled technology.

Key elements of PTR include:

- Event performance analytics performed on all customers with AMI;
- Pre-event and post-event email notifications;
- Rewards earned by those enrolled in “Points-and-Rewards”;
- Rewards awarded based on participation in up to twenty PTR events per year; and
- No penalties for failure to reduce load during PTR events.

National Grid reviews load forecasts for the New York Independent System Operator (“NYISO”) system and Zone F, which includes Clifton Park, as well as local Clifton Park weather forecasts, to determine whether to call a PTR event, also referred to as a “Conservation Day.”

PTR events are entered into two systems: one triggers event notifications to Clifton Park customers; and the other sets in motion the energy use predictive model, which will compare predicted values to actual AMI metered usage. The second system is used to determine curtailment participation. Over 8,000 pre-event emails notifying customers that a Conservation Day is scheduled are sent to Clifton Park customers for each event.

Once the Company determines the curtailment performance for the Conservation Day, each customer’s electric service account is assigned a value of “true” or “false” for each event, based on whether the customer curtailed during the event. Accounts enrolled in the Points-and-Rewards program which are assigned a value of “true,” are then awarded points. National Grid tracks customer enrollments in Points-and-Rewards as a measure of customer engagement – enrollment has increased each month as the Project has progressed.

Figure 4: Customers Enrolled in Points and Rewards

The Company implemented a fourth season of PTR/Points-and-Rewards during the summer of 2020 within the original Project budget. A summary of PTR year-over-year performance can be found as Appendix B. In addition, initial procurement discussions have taken place to assure continued operation of AMI and portal functionalities.

Timeframe	Completed Milestones
3rd Quarter 2020	• PTR summer 2020 was completed with 8 Conservation Days called. • PTR year-over-year performance can be found in Appendix B.

2.1.5 Advanced Analytics and Energy Forecasting

National Grid's Advanced Analytics and Energy Forecasting team developed the residential energy use predictive model to determine the expected energy use during PTR events. The predictive model uses prior customer level energy consumption data and event weather conditions to predict customers' energy consumption during events. The predicted values are compared to the actual AMI data to determine whether customers curtailed energy use and to ascertain which customers earned points. The results of the analyses are also used to determine if the aggregated community load meets certain threshold requirements for bidding into the NYISO wholesale electricity market. In addition, the Advanced Analytics and Energy Forecasting team has supported the development of innovative pricing rate designs.

Timeframe	Completed Milestones
3rd Quarter 2020	• Continued to support normal business operations. • Continued to develop innovative rates deployment strategy.

2.1.6 Time-of-Use Price Signals

As a result of the AMI collaborative, National Grid is continuing to look for opportunities to test innovative pricing rate designs using AMI infrastructure. The Company filed two proposals for rates to test in Clifton Park (*see* Case No. 19-E-0111). Work to refine the time-varying rate structures and the research methodology is ongoing.

Timeframe	Completed Milestones
3rd Quarter 2020	• Continued strategic alignment of Clifton Park, AMI Business Case, and innovative pricing designs.

2.1.7 Distributed Energy Resource Opportunities

National Grid seeks to animate the market by facilitating DER provider opportunities as part of the Project. DER products and services will be opt-in offerings to customers, publicized via the customer engagement channels outlined above (*e.g.*, the National Grid Marketplace and related Solar Marketplace). DER services may include energy efficiency, demand response, or renewable distributed generation opportunities. The Company is continuing to monitor the COVID-19 situation and adjust its proactive outreach and communications strategies with customers as necessary.

Timeframe	Completed Milestones
3rd Quarter 2020	• Continued evaluation of DER promotions.

2.1.8 Community Choice Aggregation

In 2017 National Grid engaged Clifton Park officials and community members on potential adoption of a utility-supported CCA; however, the Town decided not to pursue the CCA option.

2.1.9 Project Management

A group of individuals in the Company work to manage the Project, keeping it on track regarding scope, schedule, and budget, while also lending visibility into processes, accomplishments, and financial tracking. The project managers regularly engage in and promote, the following:

- Weekly Core Team Status Reporting;
- Monthly General Staff Meetings;
- Quarterly Commission Reporting;
- Issue Tracking;
- Lessons Learned Recording and Review;
- Change Log Processes; and
- Financial Reporting activities.

Timeframe	Completed Milestones
3rd Quarter 2020	• Conducted weekly status reviews with core team leads, monitoring progress, providing corrective measure(s), and escalating issues, as needed.
	• Provided Project updates for management review.

2.1.10 Innovative Pricing

On February 14, 2019 and October 22, 2019, National Grid submitted proposals to implement an innovative pricing demonstration to leverage the status of the current Project (*see* Case No. 19-E-0111). The proposal, which includes draft tariff leaves, rate design options, and a related budget, remains pending before the Commission.

The Company has worked closely with Staff to develop a proposal for testing demand-based delivery rates based on the Standby rate design. However, at this time the Company intends not to pursue the project actively on the basis that the Commission is separately considering a Standby rate package, which will be available to residential customers. The Company anticipates action on such a rate package could occur in Spring 2021 or thereafter.

Timeframe	Completed Milestones
3rd Quarter 2020	• Continued work to identify and design potential innovative pricing rate and test scenarios.

2.2 Challenges, Changes, and Lessons Learned

Qtr	Issue or Change	Resulting Change to Project Scope/Timeline?	Strategies to Resolve	Lessons Learned
Q3.20	A previous event file was transmitted for distributed rewards.	Some customers did not receive their appropriate reward until after correction was made.	Accurate data was transmitted to resolve. Analysis of impact was made. All customers made whole.	Event protocols need to assure previous event files are cleared from server in preparation of next event.
Q3.20	Gas ERTs deployed in Clifton Park will cease being manufactured in 2021.	Near term strategy for projected replacement ERTs by model comparing current inventories to projected need.	Projected 5-year need based on industry failure rates; and compared to current inventories.	ERT models have various rates of inventory. Also, ERTs supporting AMR infrastructure can be encrypted to support cellular AMI infrastructure.

3.0 Next Quarter Forecast

During the fourth quarter of 2020, the Project team will develop a strategic plan for program operations for 2021 (*e.g*., another season of PTR and potential other promotions). The Project team will continue to develop plans related to scope, schedule, budget, and resources for testing rate designs. The Company will also continue to monitor potential COVID-19 related impacts and adjust, as necessary, any customer communications.

3.1 Check Points/Milestone Progress

3.1.1 Summary

	Checkpoint/Milestone	Anticipated Start-End Date	Revised Start-End Date	Status
1B	Phase 1: Network Configuration and Meter Deployment	1/2/17 – 6/16/17	1/2/17 - 7/17/17	Complete
1B	PTR Operations	7/1/17 - 9/30/19	7/1/17 – 9/30/21	On-Track (green)
2	Phase 2: VVO; REV Operations and Evaluation	6/19/17 – 3/31/20	6/19/17 – 3/31/21	On-Track (green)
3	Phase 3: Project Wrap-up	10/1/19 – 9/30/20	10/1/2020 – 3/31/2021	On-Track (green)
4	Phase 4: Innovative Pricing	9/1/20- 7/1/2024	4/1/2021 -	Delayed start, at risk of on-time completion, or over-budget (yellow)

Key

- (green) On-Track
- (yellow) Delayed start, at risk of on-time completion, or over-budget
- (red) Terminated/abandoned checkpoint

3.1.2 Work Stream – 4th Quarter 2020

Work Stream	Future Milestones	Status
IT	• Support Project via National Grid's IT Support team. • Meter Data Management System (MDS) upgrade	On-Track (green)
AMI	• Support normal business practices related to move-in/out of customers.	On-Track (green)

Work Stream	Future Milestones	Status
VVO	• Continue study to evaluate overall system performance, leveraging AMI data for additional efficiencies. • VVO site acceptance testing, followed by initiation of M&V period.	
Customer Outreach	• Continue customer communications and education engagement.	
PTR	• Develop plans for future PTR offerings.	
Advanced Analytics and Energy Forecasting	• Provide continued support to Project team. • Prepared to calculate PTR curtailment results.	
TOU Price Signal	• Not pursued under initial Project; however, Project team anticipates transition to innovative pricing.	
DER	• Not continued due to anticipated transition to innovative pricing.	
Project Management Group	• Conduct weekly Project update meetings.	
	• Monitor and report Project key performance indicators.	
	• Continue tracking, monitoring and controlling the Project schedule, tracking on a weekly basis.	
	• Continue tracking, monitoring and controlling the Project financials, tracking on month-by-month basis.	
	• Continue to identify, monitor and manage risks and issues as they arise.	
	• Work with AMI team on future rate structure strategies.	
Project Evaluation	• Develop Project evaluation plan.	
	• Evaluate additional AMI data analytics to capitalize on availability of meter data.	

4.0 Work Plan and Budget Review

4.1 Updated Work Plan

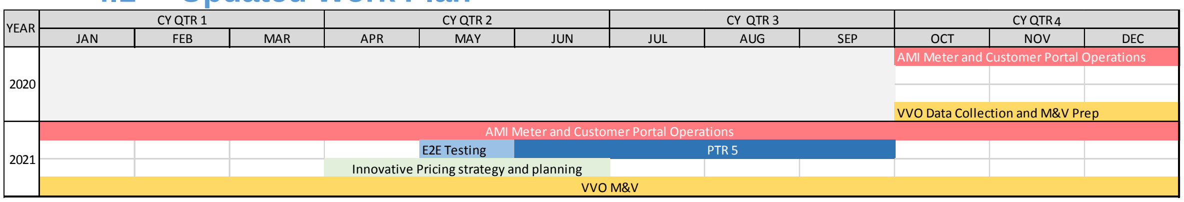


Figure 5: Current Year Work Plan

Figure 5 represents the work plan for the Project. AMI meters and the customer portal will remain operational, PTR operations will continue, and VVO data collection will commence to support measurement and verification efforts.

4.2 Updated Budget

	3rd Qtr 2020 Actual Spend	Project Total Spend to Date	Project Initial Budget	Revised Budget	Remaining Balance
CAPEX					
	-	8,694,206	12,516,057	8,766,057	71,851
OPEX					
	306,817	9,744,146	14,437,176	13,936,353	4,192,207
TOTAL					
		18,438,352	26,953,233	22,702,410	4,264,058

Note: Total spend includes 2019 payment of $432,736 for software services through March 31, 2021 to support the customer portal and PTR.

5.0 Progress Metrics

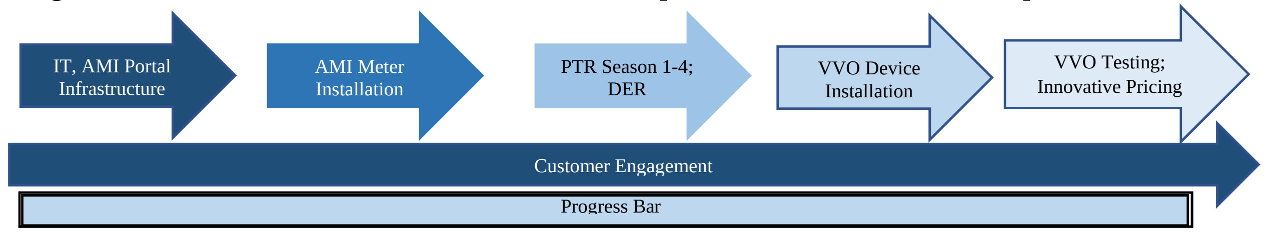
Checkpoint[5]	Progress / Target Completion
Infrastructure	
AMI Acceptance vs. Opt Out	Continuing to monitor opt-out rates as Project progresses, and through the life of the Project. Current opt-out rate is 8.8 percent.
VVO System Benefits	Established infrastructure required to enact VVO and monitor progress. Equipment installation and commissioning completed. Initiated VVO evaluation period.
Customer Outreach and Engagement / Deep Energy Insights and Actionable Information	
Customer Outreach and Engagement	Continuing engagement through life of the Project. Annual surveys tracked against initial baseline survey.
Customer Energy Portal Engagement	Continue customer engagement metrics related to portal use, PTR participation, etc.
Price Signals	
PTR	Began PTR in July 2017; continue evaluation through life of the Project regarding participation rates and curtailed load.
TOU Price Signal	Strategic transition to innovative pricing demonstration.
DER	
DER Opportunities	Promotion of Connected Solutions demand response and related technologies, National Grid's Solar Marketplace, and energy efficient pool pumps and pool pump timers.

[5] *See* Implementation Plan at pages 24-26, for specific metrics.

6.0 Appendix A – One Page Summary

nationalgrid **Clifton Park REV Demo** **09/30/2020 (Q3 2020)** **Overall Status (Active)**

Project Start Date: 01/17/2017 **Project End Date:** 03/31/2021 for initial phase
Budget: $22,702,410 **Current Quarter Spend:** $306,817 **Cumulative Spend:** $18,438,352



Project Summary: Address REV principles to reduce peak demand, increase DER adoption and give customers greater insight into their energy usage so they can make more informed energy decisions. Primary deliverables include: installation of approx. 13,300 AMI electric meters and 11,500 gas ERTs, energy management education and engagement; implementation of a Peak Time Rewards (PTR) program; improve system-wide efficiency. Partners include Itron, Opower/Oracle, Utilidata; vendors include Wipro, Verizon, Navigant. A petition proposing transitioning the Project into an innovative pricing REV demonstration project was filed October 22, 2019.

Cumulative Lessons Learned		
The Customer	**Market Partner**	**Utility Operations**
• Customer participation has been moderate despite specific marketing campaigns and customer outreach meetings. • Meter acceptance rate > 90% • Portal usage is at ~24% • Points-and-rewards enrollment ~16%	• DER promotion dependent on available information to disseminate (*e.g.*, Solar Marketplace launch). • Partner system restrictions limit availability to deliver PTR.	• Meter deployment was challenged by temporary workforce hiring. • VVO construction was challenged by reallocation of resources due to storm duty obligations.

Application of lessons learned: National Grid is aligning its AMI opportunities in Clifton Park with its broader AMI Business Case through its proposal to transition Clifton Park into an innovative pricing REV demonstration. An innovative pricing demonstration will include omni-channel marketing, multiple touch-point customer engagement, along with an enhanced customer portal to deliver the benefits of AMI technology to better manage energy usage and succeed on innovative pricing designs.

Issues Identified: Rewards-type structure is not sustainable and does not align with other regulatory initiatives. Innovative pricing structures and research design not finalized.

Solutions Identified: VVO M&V data currently being analyzed. PTR rewards points has been extended for another summer to bridge build of innovative pricing structures and delivery.

Recent Milestones/Targets Met: PTR summer 2020 has completed.

Upcoming Milestones/Targets: Develop innovative pricing strategy.

COVID-19: Enacted Business Continuity Plan March 12; monitoring vendor/load impacts; adjusting communications.

7.0 Appendix B – PTR 2020 Summary

ORACLE

Peak Time Rewards Results

National Grid – Clifton Park

Mary Claire Moran

October 2020

COVID-19 and Customer Usage Patterns

Learnings from the July 31, 2020 Opower COVID-19 Live Update

July 2020

Trends across US service territories

It's a warm summer in many service territories

Temperatures are high, contributing to higher usage and peak usage

COVID is driving summer usage and peaks higher

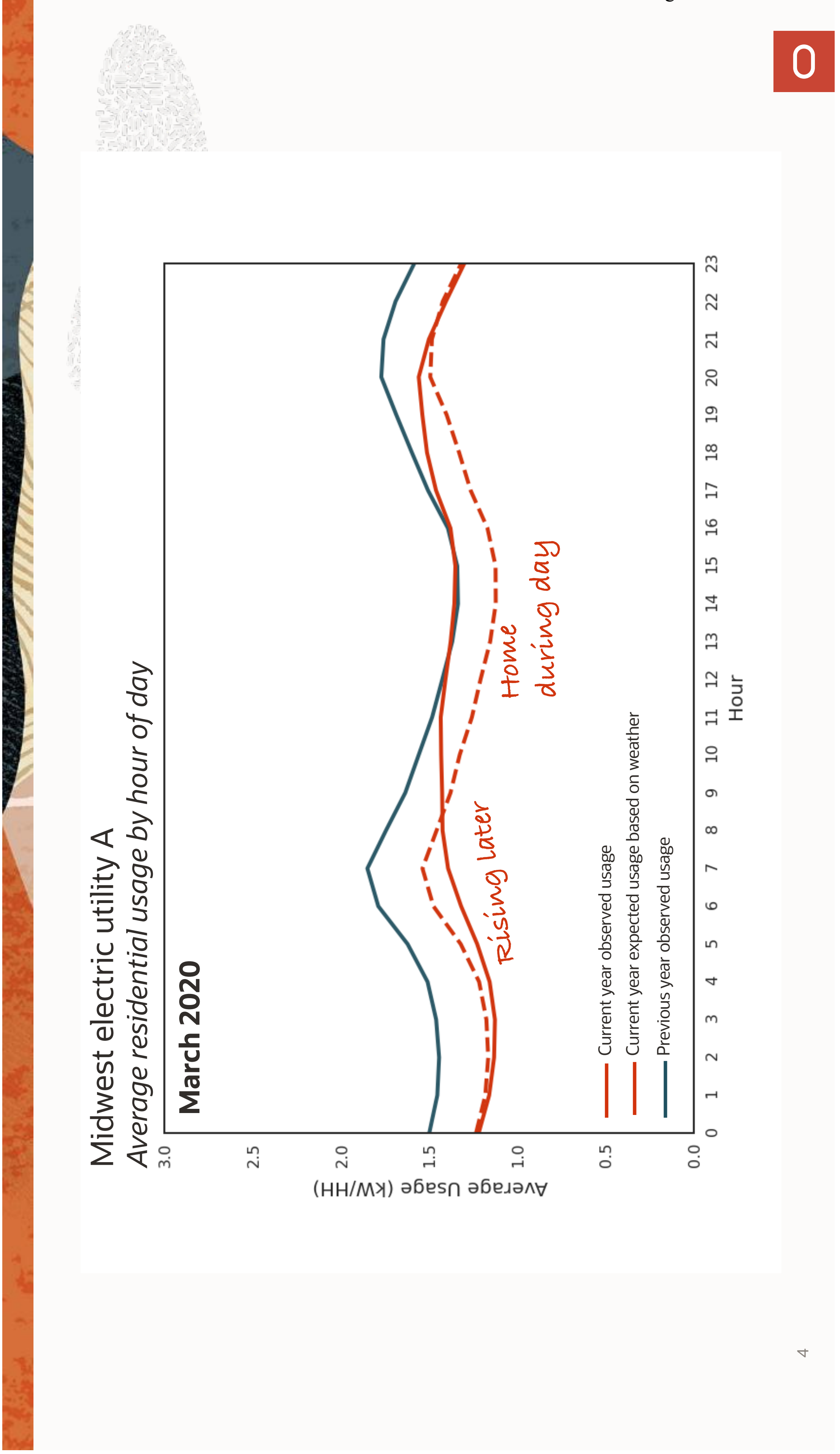
Almost every service territory shows higher usage in the summer 2020 than last year, particularly during peaks

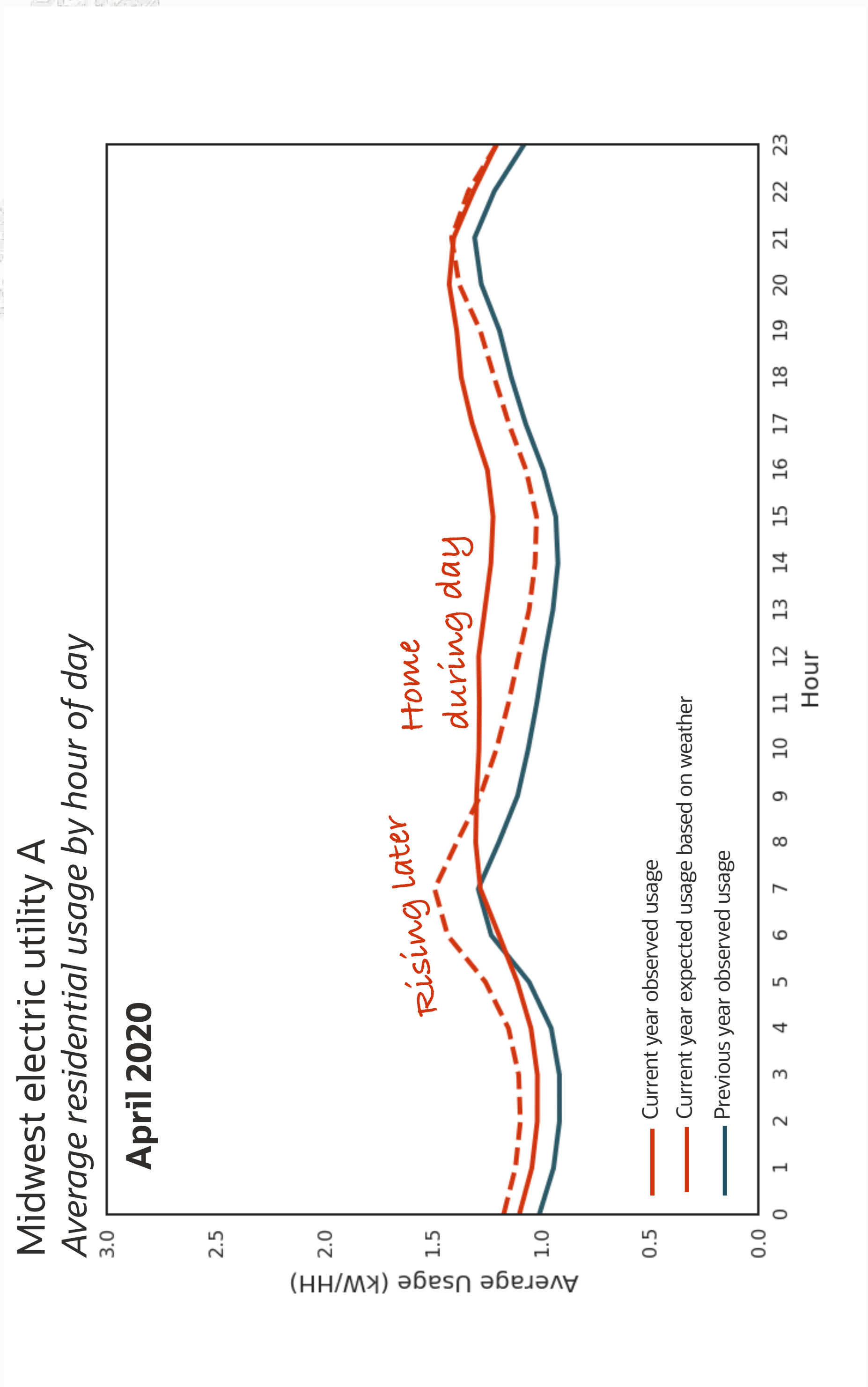
- In 20% of cases, it was cooler this year but COVID still pushed usage higher than last year
- In 35% of cases, temperatures were similar to last year but COVID increased usage
- In 45% of cases, it was hotter this year and COVID further increased usage

COVID is adding strain on distribution infrastructure

Increasing spikes in locational demand in residential areas may exceed distribution capacity

3

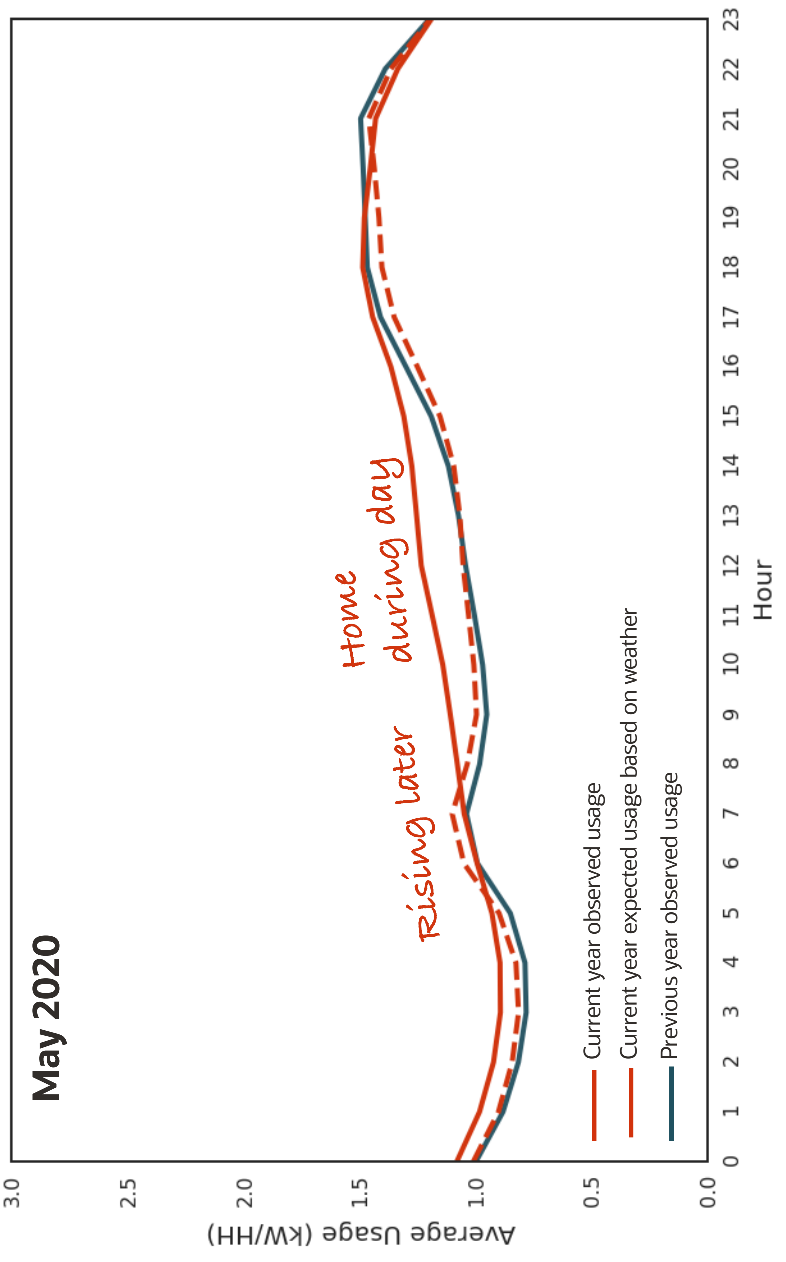

Midwest electric utility A
Average residential usage by hour of day
March 2020
Average Usage (kW/HH)
3.0
2.5
2.0
1.5
1.0
0.5
0.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour
Rising later
Home during day
Current year observed usage
Current year expected usage based on weather
Previous year observed usage
0
4


Midwest electric utility A
Average residential usage by hour of day
April 2020
Rising later
Home during day
Average Usage (KW/HH)
3.0
2.5
2.0
1.5
1.0
0.5
0.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour
Current year observed usage
Current year expected usage based on weather
Previous year observed usage

O

Midwest electric utility A

Average residential usage by hour of day



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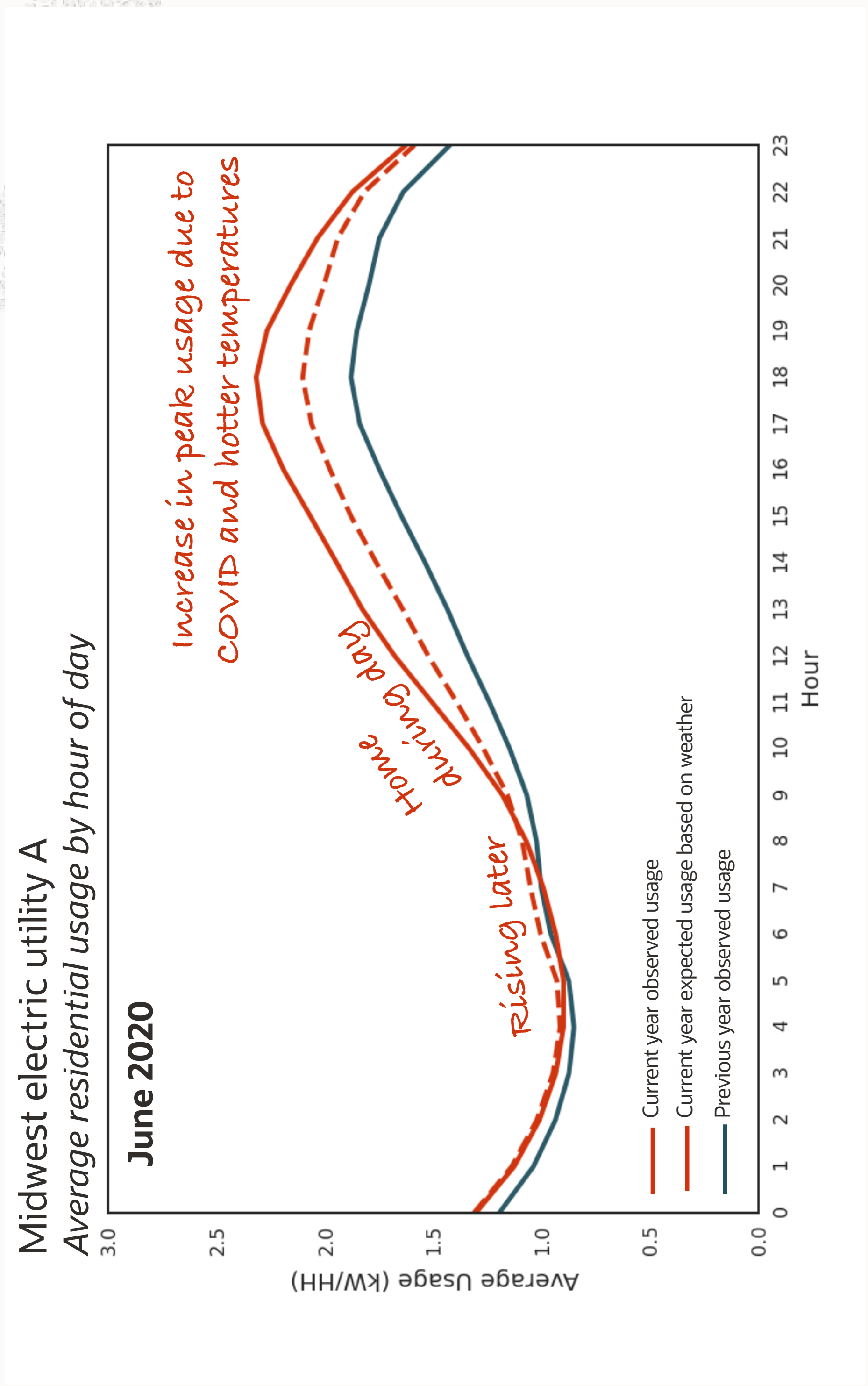
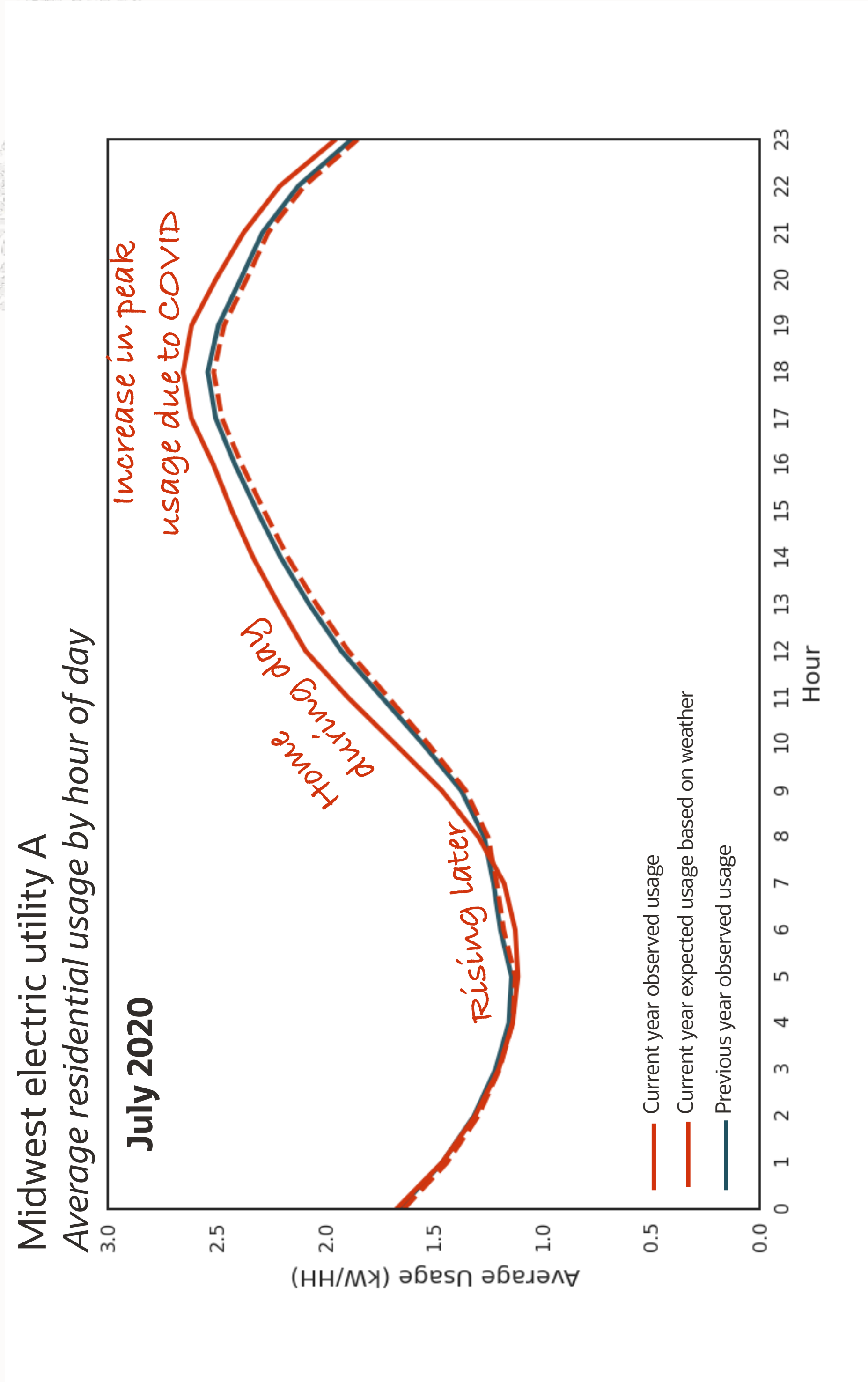
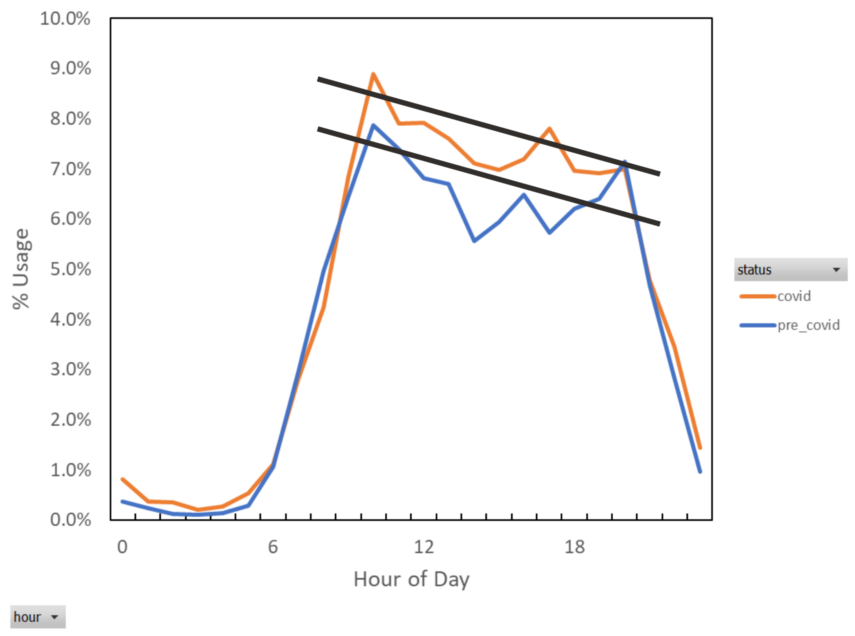

Midwest electric utility A
Average residential usage by hour of day
June 2020
Increase in peak usage due to COVID and hotter temperatures
Home during day
Rising Later
Average Usage (KW/HH)
3.0
2.5
2.0
1.5
1.0
0.5
0.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour
Current year observed usage
Current year expected usage based on weather
Previous year observed usage

7

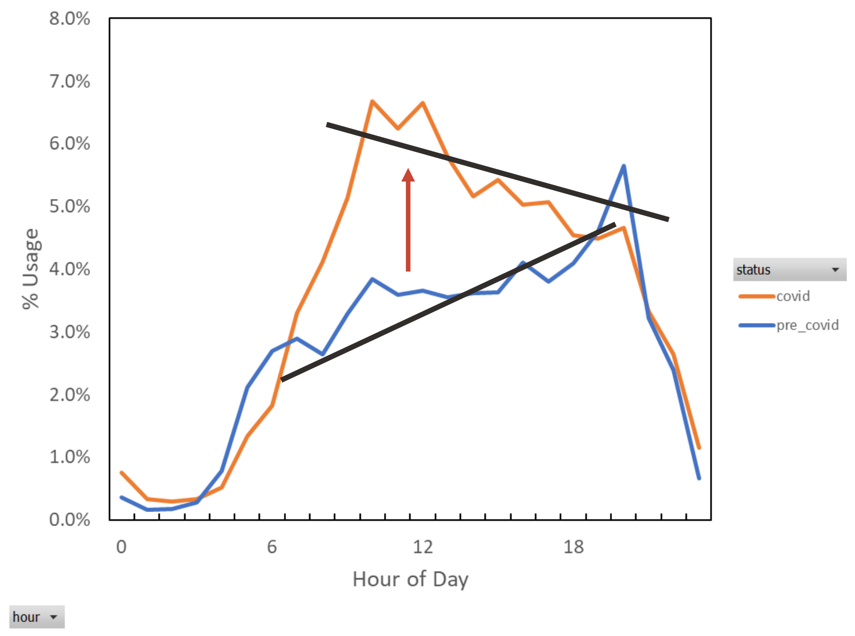

Midwest electric utility A
Average residential usage by hour of day
July 2020
Increase in peak usage due to COVID
Home during day
Rising later
Average Usage (kW/HH)
3.0
2.5
2.0
1.5
1.0
0.5
0.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour
Current year observed usage
Current year expected usage based on weather
Previous year observed usage

The “Sweatpants Effect”

Weekends look the same



Weekdays look more like weekend



Lines graphs are deep learning modeled data (East Coast) month over month.

2020 Season

2020 Season and COVID-19

- This was an atypical season due to COVID-19 since the way that customers use energy throughout the day has changed due to social distancing
- Updated language in the outbound comms to be sympathetic to the challenges of COVID-19 and more time spent at home
- Non-COVID friendly tips were suppressed by Opower (not CDC compliant, not social distancing)
- COVID-19 caused increased electric usage through out Summer 2020

Pre-Season Welcome Letter

nationalgrid

1 Willow Street, Suite 2
Southborough, MA 01772-1026

<MONTH XX, XXXX>

<ADDRESS_LINE_1>
<ADDRESS_LINE_2>
<ADDRESS_LINE_3>

Get rewarded for saving energy on Conservation Days

As a participant in Smart Energy Solutions, you're invited to join your community in saving energy on Conservation Days this summer.

With more people staying close to home right now, we know it may be challenging to use less energy on Conservation Days this summer. But, when you do, not only will you be helping the environment, you'll also be eligible to earn points to redeem for eGift cards at places like Target, Amazon, Starbucks, and more. And, because it's a bigger challenge this year, your points can add up even faster: **Use less energy, earn 100 points; use considerably less energy and earn 500 points.**

Make sure you're signed up for our Points and Rewards program so you don't miss out on your points. Here's how:

1. Log in or create an account at ngrid.com/uny-rewards.
2. Select "Saving Tips & Rewards."
3. Select "Get Rewards" then click the "GET STARTED" button.

Happy saving!

Saving on Conservation Days is easy. Participate with these simple steps:

Before:
Look out for notifications
We'll notify you via email to let you know about the upcoming Conservation Day.

During:
Lower your use
Take simple steps, like those on the back of this report, to lower your use.

After:
See how you did
A few days later, we'll let you know whether you saved energy and earned points.

Flip this letter over for your Conservation Day savings plan

NGNY_0020_WELCOME_LETTER_DRR3

ngrid.com/uny-rewards | 1-877-466-3433 (Monday–Friday, 8am–5pm)

Here's how you can save on Conservation Days

A Conservation Day is a summer day predicted to be extra hot, leading to higher-than-normal energy use. Lowering your energy use on Conservation Days will keep costs down and contribute to a greener community. Your participation in the Conservation Day program is optional, but each small step you take can have a significant environmental impact.

Spend time outside to stay cool

One of the easiest and most effective ways to reduce your home's electricity use during conservation days is to spend some of that time outside. We know sticking close to home makes that challenging, but try some of these fun backyard or front-stoop activities:

- Spread a blanket in the shade and play cards or board games.
- Fire up the grill for a backyard picnic (don't forget the popsicles!).
- Break out colored chalk for a sidewalk art competition.

While you're outside, make sure to raise your thermostat by 10°F.

Use fans and reduce air conditioning

During Conservation Days, when electricity demand is high, the need to stay cool tends to increase as well. Small actions during conservation days can have big impacts.

Most people find they can raise the thermostat temperature by 3-4°F and still stay comfortable. Close curtains and blinds to keep sunlight from entering your home and stay close to fans instead of using air conditioning to keep cool.

Put off household chores

Appliances can account for up to 20% of total energy use in a typical household and can unintentionally heat up your home.

To help your community save energy on Conservation Days, try steps like running the dishwasher after conservation hours or doing laundry on the weekends. You can also talk with your household to make plans for Conservation Days and identify what other appliance-related chores you can postpone.

To find even more ways to save, visit **ngrid.com/uny-savings-tips**.

Pre Event Message

nationalgrid

Jane Doe
Acct # 22

We're expecting high energy demand today.
Help conserve energy by reducing usage during peak hours.

November 10
12pm - 1pm

Earn 100 points
Earn 500 points

These days we're all spending more time at home – and using more energy. By shifting the time you use energy during the hottest days of summer you can manage your energy costs, reduce stress on the grid to benefit the community, *and* earn points in our Points and Rewards program, redeemable for eGift cards.

This summer, we want to help you prepare for days when energy demand is expected to peak while you enjoy the safety and comfort of your home.

Use less energy today to earn **100 points**; use considerably less energy and earn **500 points**

But you have to sign up to get your points! Here's how:

1. Log in or create an account.
2. Select "Savings Tips & Rewards."
3. Select "Get Rewards" then click the "GET STARTED" button.

What's a Conservation Day?

A Conservation Day is a summer day that is likely to be extra hot, which means people will be using more energy than normal. By lowering your use on Conservation Days, you can keep costs down and contribute to a greener community.

Ways to Save

Close window shades and blinds

Sunlight passing through windows heats your home and makes your AC work harder. You can block this heat by closing your window blinds or drapes. Then raise your AC temperature by 3-4°F to save electricity.

Use fans and reduce air conditioning

Fans can help you beat the heat while reducing your AC needs. Every degree counts. Raise your thermostat's setting by 3-4°F during a Conservation Day and stay close to fans to help keep cool while lowering your electricity use.

Enjoy unplugged activities

Put off running the dishwasher or doing laundry until after the Peak Event. Instead of watching TV or using electronics that need to be plugged in, read a book, play a board game, or spend quality time with your household.

SEE MORE WAYS TO SAVE

Open only to current National Grid customers in New York who have a valid email address and are at least 18 years of age. Rewards available only while supplies last. This program and any reward offered are void where prohibited by law. For more information, see the Terms of Service.

Have questions? Call 1-800-664-6729 (Monday-Friday, 8am-5pm)

Unsubscribe from these emails

National Grid
National Grid NY Home Energy Reports
1 Willow Street, Suite 2
Southborough, MA 01772-1026

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Post Event Messages

nationalgrid

Jane Doe
Acct # ***0000

Great work!

You used less energy on the last Conservation Day, from 1pm to 7pm on June 11, and now have 100 more points in your National Grid Points and Rewards account.

100 points

Be on the lookout in your inbox for the next Conservation Day, so you can keep earning points and helping the environment.

Want to keep saving energy in the meantime?

SEE MORE WAYS TO SAVE

Your points may take up to 1 week to appear in your National Grid Rewards account. Open only to current National Grid customers in New York who have a valid email address and are at least 18 years of age. Rewards available only while supplies last. This program and any reward offered are void where prohibited by law. For more information, see the Terms of Service.

Have questions? Call 1-800-664-6729 (Monday-Friday, 8am-5pm)

Unsubscribe from these emails

National Grid
National Grid NY Home Energy Reports
1 Willow Street, Suite 2
Southborough, MA 01772-1026

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nationalgrid

DANIEL HEATH
Acct # *******5066

Your Conservation Day results

On the last Conservation Day, from 2pm to 6pm on July 3, you didn't save enough energy to earn points in our Points and Rewards program; but don't worry, you'll have another opportunity.

More Conservation Days are coming!

We'll give you a heads up in your inbox when the next Conservation Day is on the way.

How do we award points?

We compare how much energy your household is likely to use during the Conservation Day, based on past use and factors like the weather. Points are awarded to homes using less energy than expected.

Ways to save on Conservation Days

Close window shades and blinds
Sunlight passing through windows heats your home and makes your AC work harder. You can block this heat by closing your window blinds or drapes. Then raise your AC temperature by 3-4°F to save electricity.

Use fans and reduce air conditioning
Fans can help you beat the heat while reducing your AC needs. Every degree counts. Raise your thermostat's setting by 3-4°F during a Conservation Day and stay close to fans to help keep cool while lowering your electricity use.

Enjoy unplugged activities
Put off running the dishwasher or doing laundry until after the Peak Event. Instead of watching TV or using electronics that need to be plugged in, read a book, play a board game, or spend quality time with your household.

SEE MORE WAYS TO SAVE

View your rewards account

Open only to current National Grid customers in New York who have a valid email address and are at least 18 years of age. Rewards available only while supplies last. This program and any reward offered are void where prohibited by law. For more information, see the Terms of Service.

Have questions? Call (877) 620-1930 (Monday-Friday, 8am-5pm)

Unsubscribe from these emails

National Grid
National Grid NY Home Energy Reports
40 Washington Street, Suite 2000
Westborough, MA 01581-1088

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nationalgrid

COBURG VILLAGE
Acct # *******6013

Your Conservation Day results

On the last Conservation Day, from 2pm to 6pm on July 2, you didn't save enough energy to earn points in our Points and Rewards program. But don't give up, more Conservation Days are coming!

Did you know?

You can earn points for reducing energy use on Conservation Days, with National Grid's Points and Rewards program. Use less energy and earn 100 points; use considerably less energy and earn 500 points—then redeem your points for eGift cards.

Here's how to sign up, so you don't miss out on future opportunities to earn points:

1. Log in or create an account.
2. Select "Savings Tips & Rewards."
3. Select "Get Rewards" then click the "GET STARTED" button.

How do we award points?

We compare how much energy your household is likely to use during the Conservation Day, based on past use and factors like the weather. Points are awarded to homes using less energy than expected.

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Enjoy unplugged activities
Put off running the dishwasher or doing laundry until after the Peak Event. Instead of watching TV or using electronics that need to be plugged in, read a book, play a board game, or spend quality time with your household.

SEE MORE WAYS TO SAVE

Open only to current National Grid customers in New York who have a valid email address and are at least 18 years of age. Rewards available only while supplies last. This program and any reward offered are void where prohibited by law. For more information, see the Terms of Service.

Have questions? Call (877) 620-1930 (Monday-Friday, 8am-5pm)

Unsubscribe from these emails

National Grid
National Grid NY Home Energy Reports
40 Washington Street, Suite 2000
Westborough, MA 01581-1088

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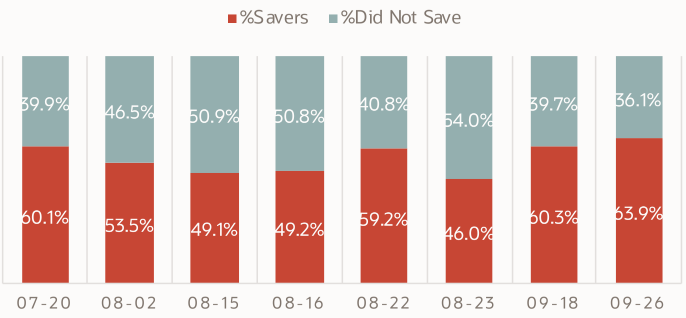
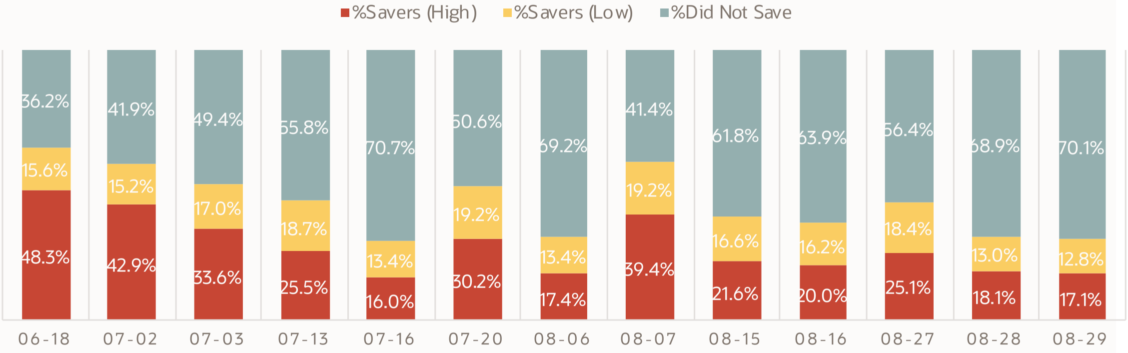
2020 season had slightly lower participation due to changing usage trends as a result of COVID-19

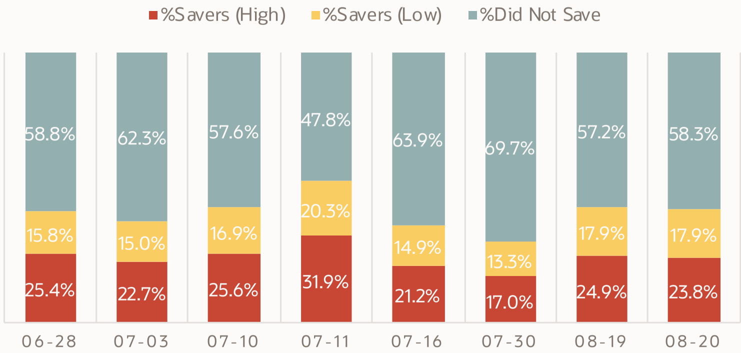
DRR SAVINGS - 2017 BREAKDOWN



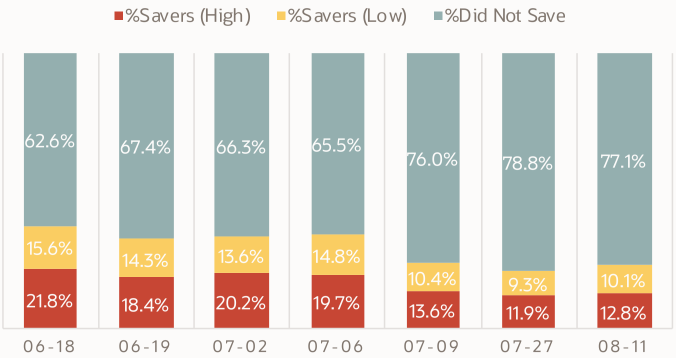
DRR SAVINGS - 2018 BREAKDOWN



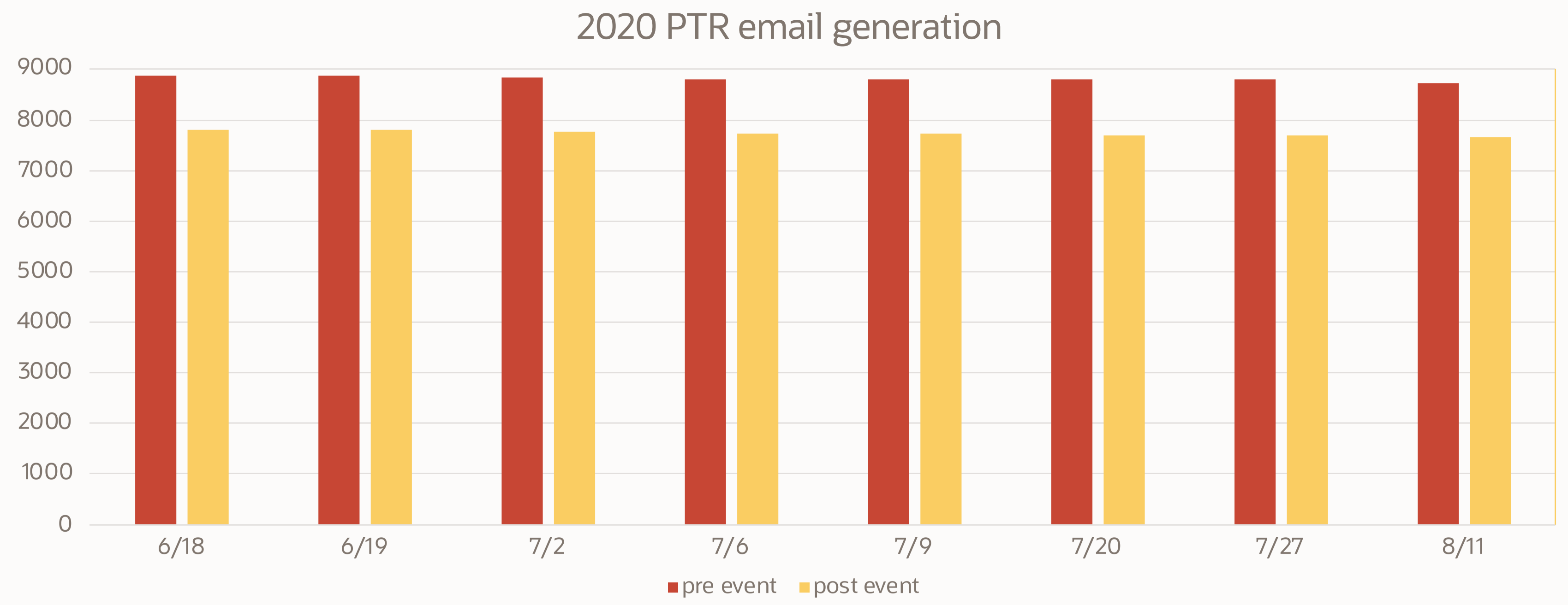
DRR SAVINGS - 2019 BREAKDOWN



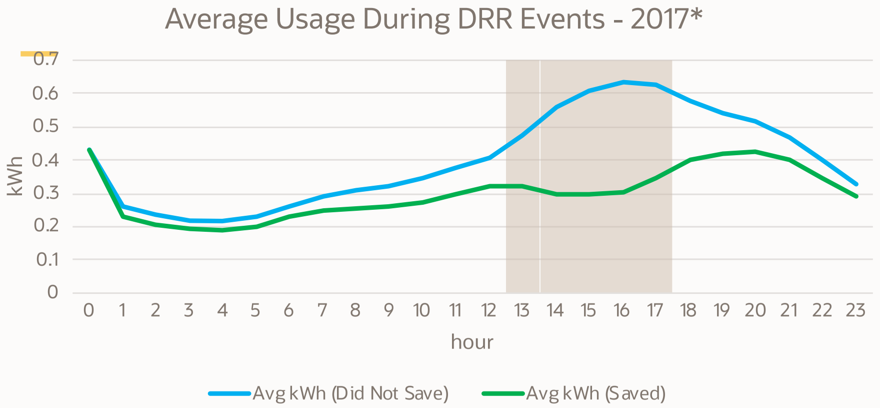
DRR SAVINGS - 2020 BREAKDOWN

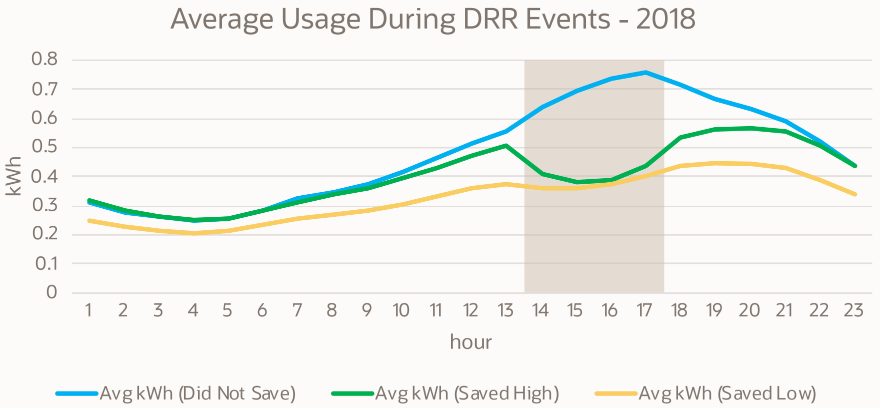


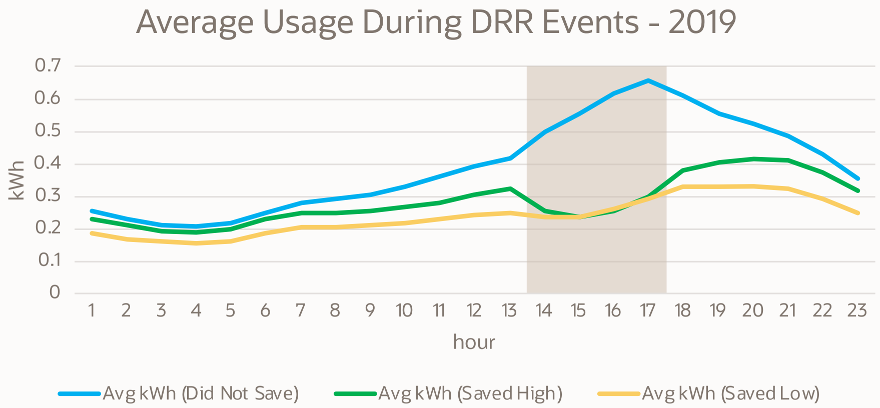
Comms generated for 2020 season

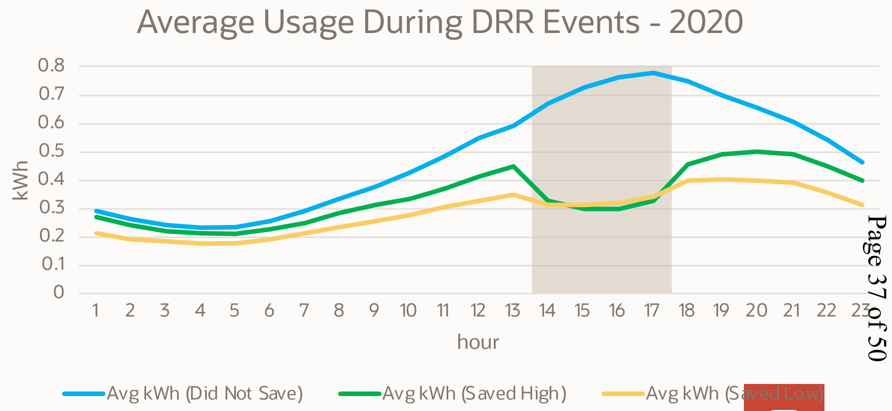


Consistent average customer energy use during event for energy savers versus non savers









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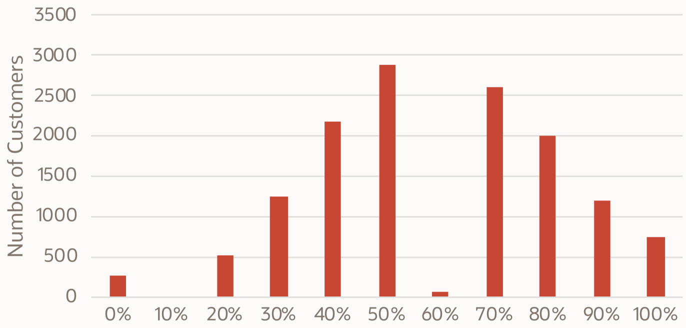
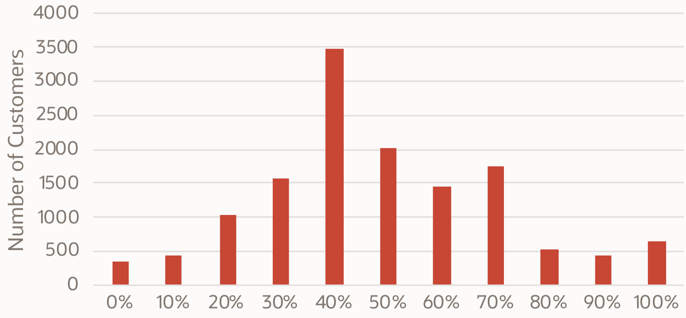
* did not distinguish high vs low savers for DRR events in 2017

In past years, customers tend to only save for half the events and relatively few customers either never save or save in every event

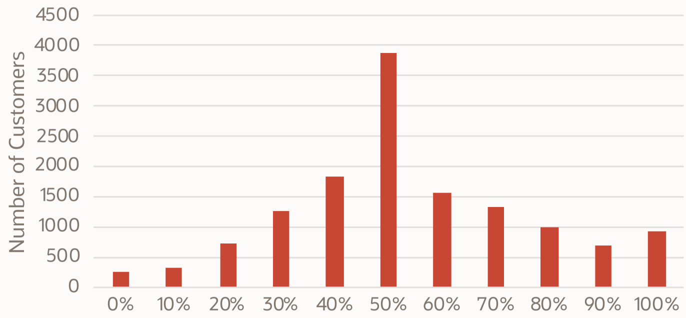
Proportion of Times Customers Saved During DRR Events (2017)



Proportion of Times Customers Saved During DRR Events (2018)

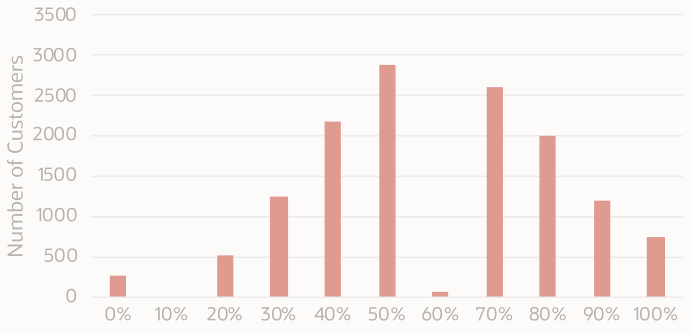


Proportion of Times Customers Saved During DRR Events (2019)

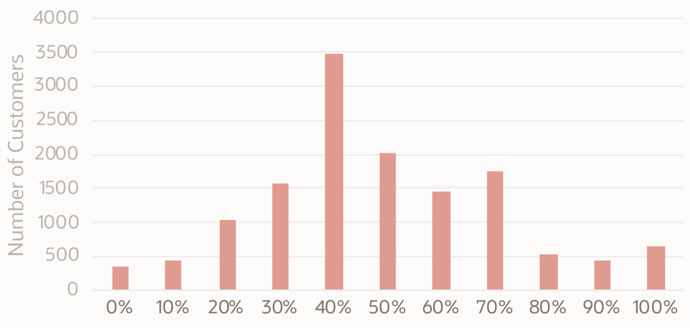


Increase in customers who are non-savers during 2020 events

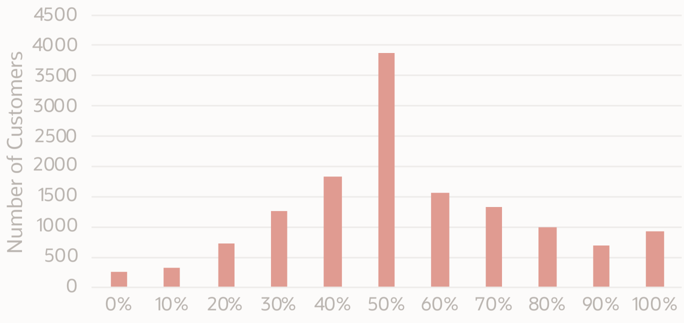
Proportion of Times Customers Saved During DRR Events (2017)



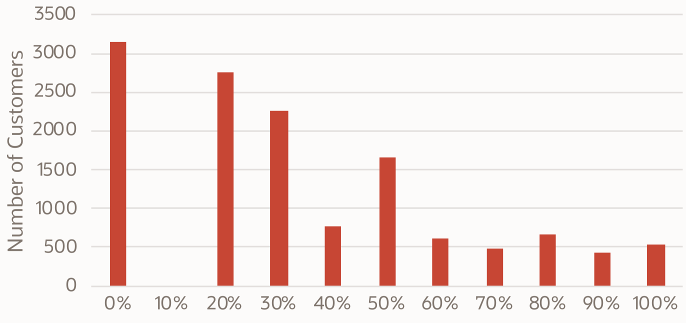
Proportion of Times Customers Saved During DRR Events (2018)



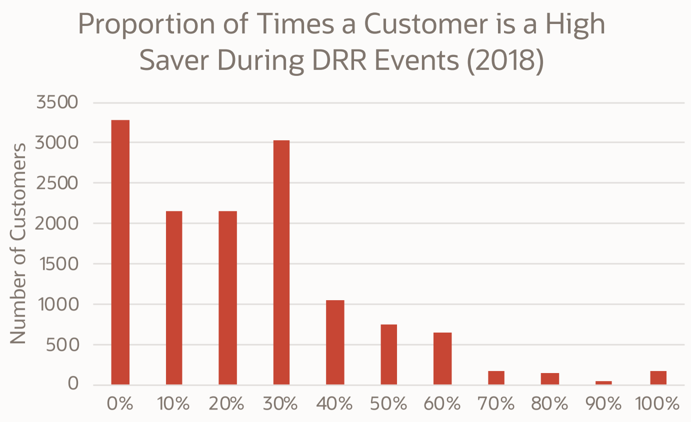
Proportion of Times Customers Saved During DRR Events (2019)

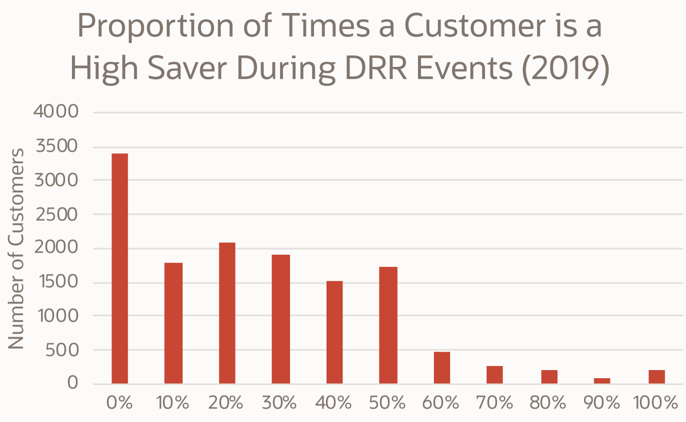


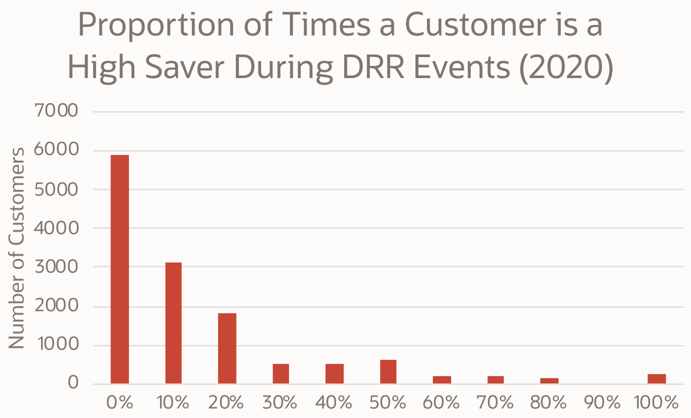
Proportion of Times Customers Saved During DRR Events (2020)



Less high savers in 2020 season compared to past seasons*







*high savers not calculated in 2017

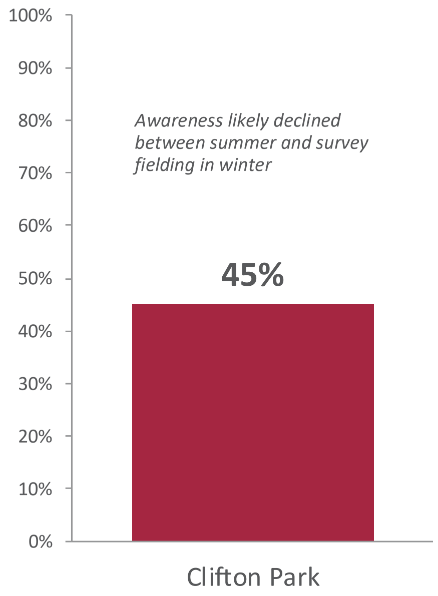
2019 Customer Engagement Tracker Results

2019 CET Survey

Customer liking of conservation days exceeds motivation to save

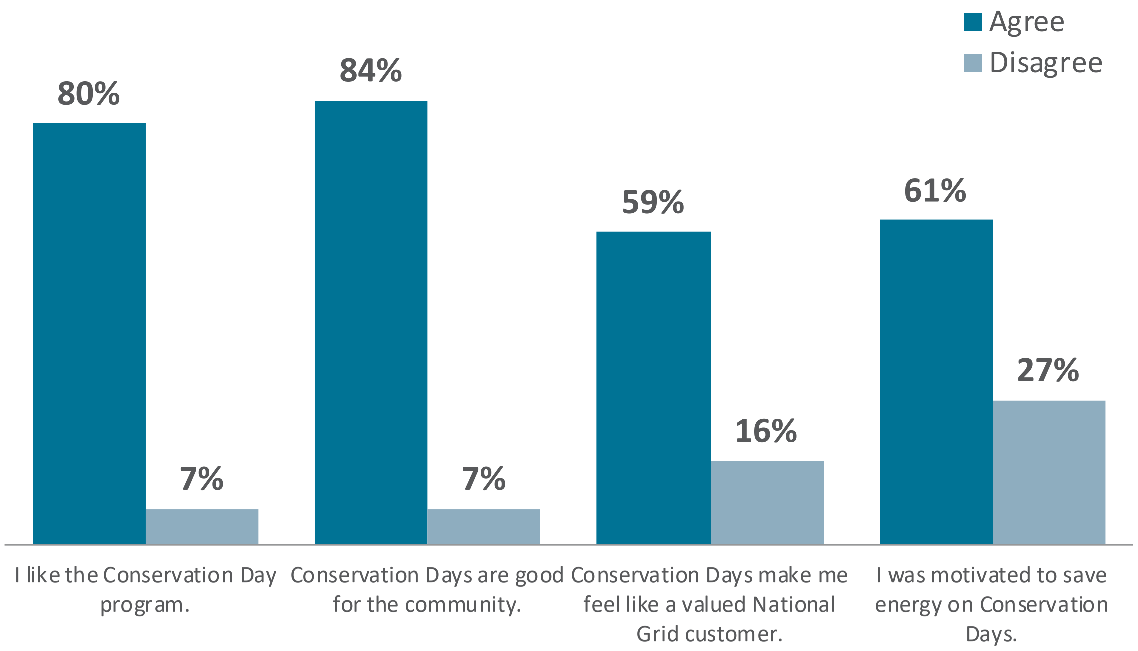
Conservation Day Recall

98 Clifton Park customers (unweighted)



Conservation Day Reception

Bottom/Top 2 Box; 5pt. agreement scale (unweighted)



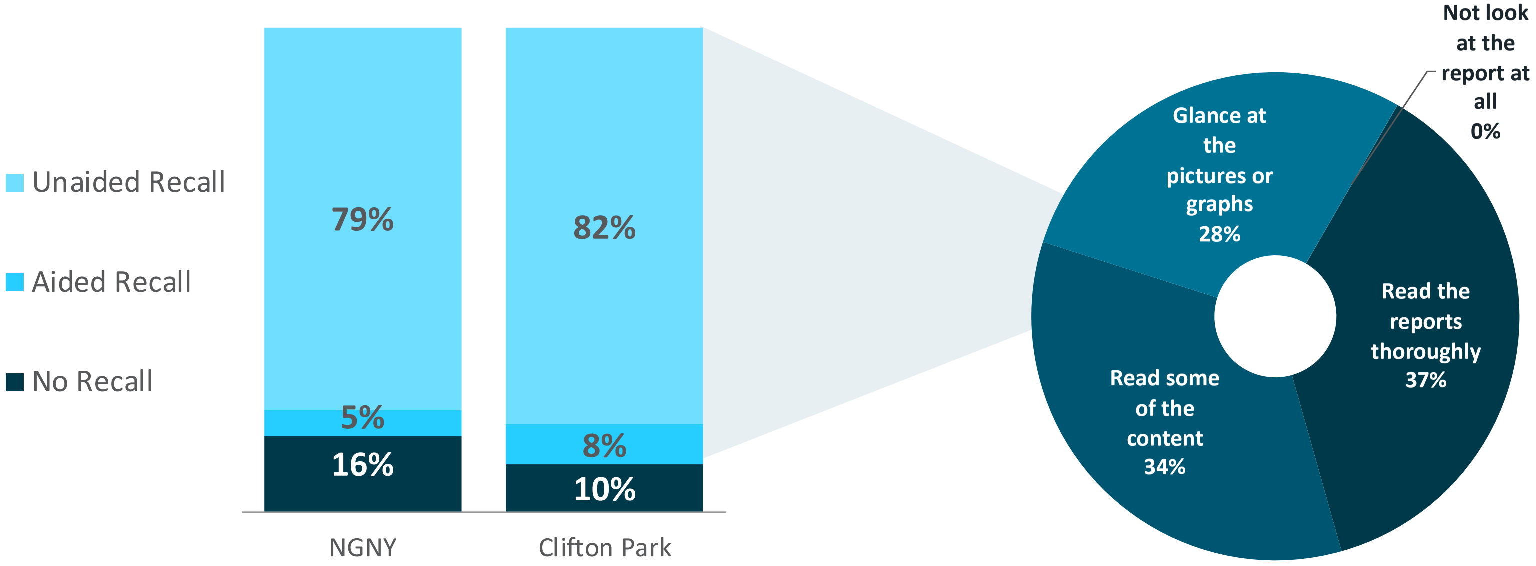
This summer, some customers with central AC were sent communications about upcoming Conservation Days…
Do you remember receiving these Conservation Day communications?

2019 CET Survey

90% of Clifton Park recipients reading reports in some way

Home Energy Report Recall

Home Energy Report Reading



90% Clifton Park Overall Readership of HER

In the past six months, do you remember receiving a Home Energy Report from National Grid about your in-home energy use?

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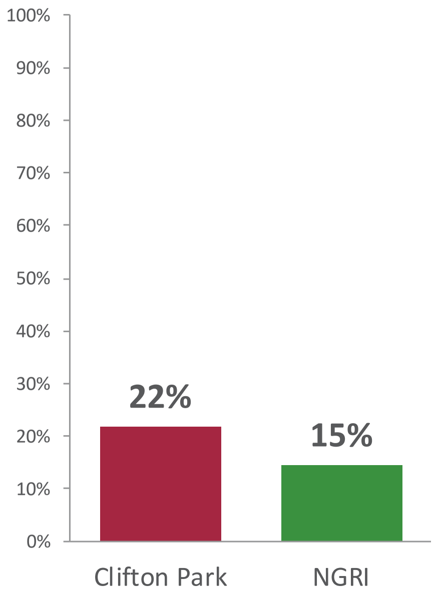
2019 CET Survey

Lower levels of high usage alert recall, likely due to timing and no regular cadence of communication

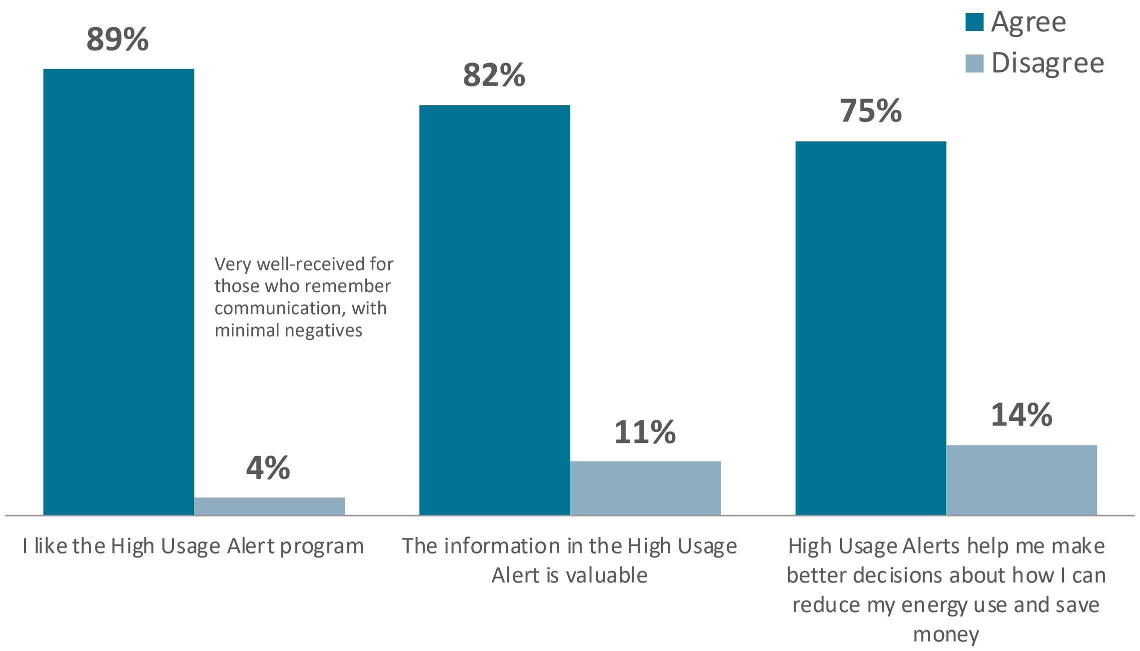
High Usage Alert Recall

165 alert recipients (unweighted)



High Usage Alert Reception

Bottom/Top 2 Box; 5pt. agreement scale (unweighted)



National Grid sends some customers High Usage Alerts when their usage is higher than normal…
Have you ever received a High Usage Alert?

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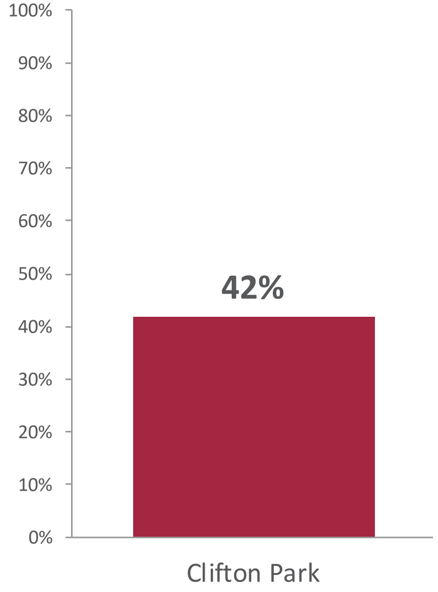
2019 CET Survey

Weekly Electricity Reports also well-received by customers, with greater recall due to frequency of delivery

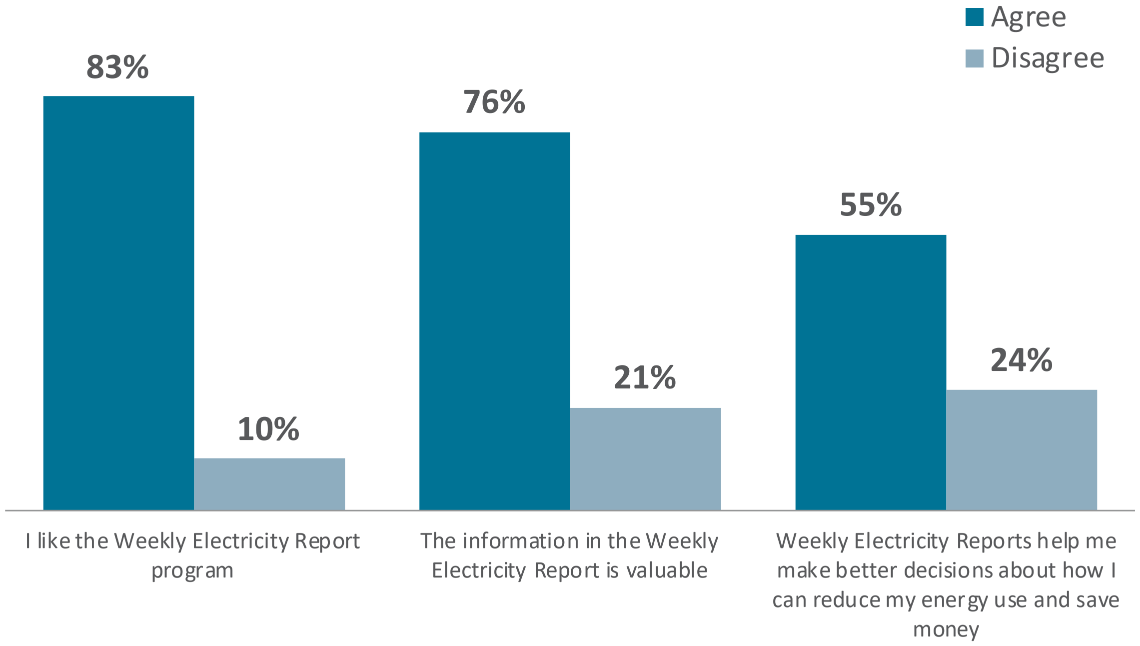
Weekly Electricity Report Recall

72 report recallers (unweighted)



Weekly Electricity Report Reception

Bottom/Top 2 Box; 5pt. agreement scale (unweighted)



National Grid emails Weekly Electricity Reports to some customers that have chosen to receive them...
Have you received Weekly Electricity Reports like this?

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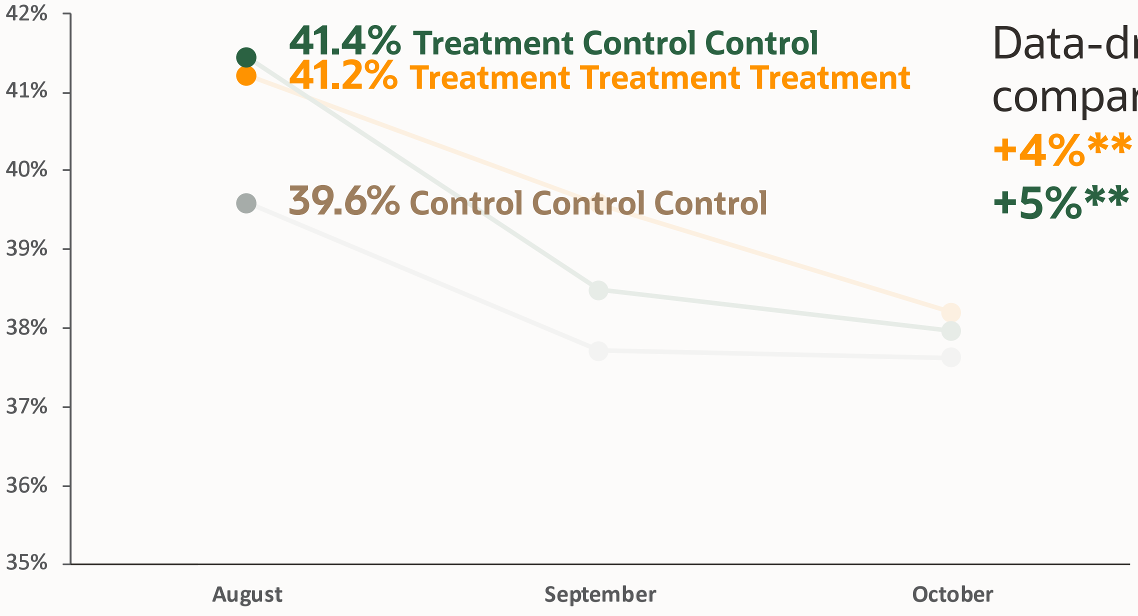
Opportunities

- Varied subject lines to encourage email opens
- Promoting program across other Opower products (HER, HBA, WAMI)
- Points awarding promotion to encourage program enrollment

Marginally higher open rates among data-driven subject lines

Open Rates
174,133 customers



Data-driven subject line increased opens compared to Control across both groups:

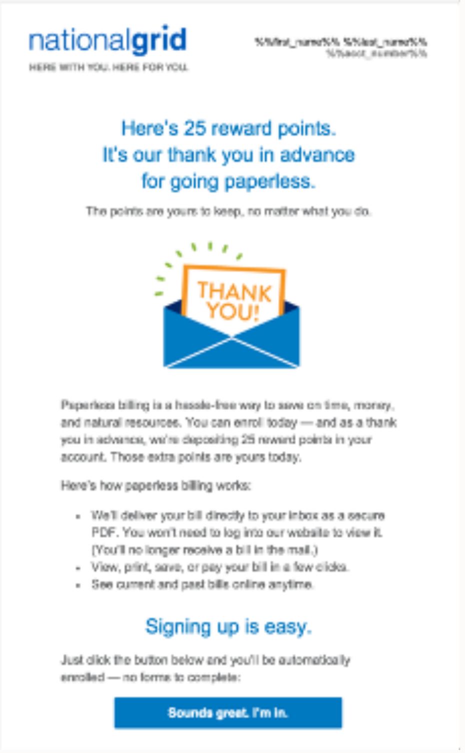
+4% Treatment Treatment Treatment**

+5% Treatment Control Control**

** 95% significant difference
* 90% significant difference


Cross product promotion
28

National Grid offered points to customers to sign up for paperless billing



- Simplified e-bill signup process
- Sent utility-generated e-bill promotions via outbound communications
- Points equivalent of $2 incentive for eBill sign-up
- Tested two points scenarios (shown left), which performed equally as well

Points promotion increased program sign-ups

Customers went online

Customers signed up for eBill

7.7%

of enrolled customers signed up for paperless billing (compared to a baseline monthly enrollment of 0.2% - 0.4%)