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April 1, 2022

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: NSTAR Electric Company d/b/a Eversource Energy 2018-2021 Grid Modernization Term Report, D.P.U. 22-40

Dear Secretary Marini:

On behalf of NSTAR Electric Company d/b/a Eversource Energy ("Eversource" or the "Company"), enclosed is the Eversource Grid Modernization Term Report. Eversource is in receipt of the February 15, 2022 memorandum issued by the Department of Public Utilities (the "Department") regarding the format of the 2021 grid modernization term reports for all electric distribution companies (the "Memorandum"). The enclosed term report complies with the format instructions set forth in the Memorandum. Also consistent with the directives in the Memorandum, the Company encloses the following: (1) a preliminary exhibit list; and (2) supporting affidavits for its 2018-2021 Grid Modernization Term Report.

Thank you for your attention to this matter. Please contact me with any questions you may have.

Sincerely,

Danielle C. Winter

Danielle C. Winter, Esq.

Enclosures

cc: Susan L. Geiser, Hearing Officer
Kerri DeYoung Phillips, Hearing Officer
D.P.U. 15-120, 15-121, and 15-122 Service Lists

COMMONWEALTH OF MASSACHUSETTS
Department of Public Utilities

NSTAR Electric Company d/b/a Eversource Energy
Preliminary Exhibit Lists

I. Grid Modernization Term Report

A. 2018-2021 Grid Modernization Term Report, D.P.U. 22-40

Initial Filing

2018-2021 Grid Modernization Plan Term Report
2018-2021 Grid Modernization Plan Term Report Appendix 1
2018-2021 Grid Modernization Plan Term Report Attachment ES-EV Program
2018-2021 Grid Modernization Plan Term Report Attachment ES-Storage Update
2018-2021 Grid Modernization Plan Term Report Attachment 2018 SI-1
2018-2021 Grid Modernization Plan Term Report Attachment 2018 SI-2/SI-3
2018-2021 Grid Modernization Plan Term Report Attachment 2019 SI-1
2018-2021 Grid Modernization Plan Term Report Attachment 2019 SI-2/SI-3
2018-2021 Grid Modernization Plan Term Report Attachment 2020 SI-1
2018-2021 Grid Modernization Plan Term Report Attachment 2020 SI-2/SI-3
2018-2021 Grid Modernization Plan Term Report Attachment Baseline SI-2/SI-3
2018-2021 Grid Modernization Plan Term Report Attachment Baseline SI-2/SI-3

II. Grid Modernization Factor Filings

A. 2018 Grid Modernization Cost Recovery, D.P.U. 19-23

Initial Filing

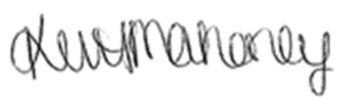
Exhibit ES-GAP/JAS/KMB	Joint Direct Testimony of Giuseppe A. Perniciaro, Jennifer A. Schilling and Kevin M. Boughan
Exhibit ES-GAP/JAS/KMB-1	2018 Grid Modernization Annual Report
Exhibit ES-ANG/JGG	Joint Direct Testimony of Ashley N. Botelho and John G. Griffin
Exhibit ES-JGG-1	Capital Authorization Policy
Exhibit ES-JGG-2	Summary of Costs by Investment Type
Exhibit ES-JGG-3	Project Master Summary
Exhibit ES-JGG-4	Project Documentation
Exhibit ES-JGG-5	O&M Invoices (Confidential)
Exhibit ES-ANB-1	Revenue Requirement Calculation
Exhibit ES-ANB-2	O&M Overhead Test
Exhibit ES-ANB-3	Incremental Labor Documentation
Exhibit ES-ANB-4	Bill Impacts

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

NSTAR Electric Company d/b/a Eversource Energy 2018-2021 Grid Modernization Term Report	)	D.P.U. 22-40

APPEARANCE OF COUNSEL

In the above-referenced proceeding, I hereby appear for and on behalf of NSTAR Electric Company d/b/a Eversource Energy.



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Dated: April 1, 2022

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

NSTAR Electric Company d/b/a Eversource Energy 2018-2021 Grid Modernization Term Report	)	D.P.U. 22-40

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Dated: April 1, 2022

B. **2019 Grid Modernization Cost Recovery, D.P.U. 20-54**

Initial Filing

Exhibit ES-GAP/KMB	Joint Direct Testimony of Giuseppe A. Perniciaro and Kevin M. Boughan
Exhibit ES-GAP/KMB-1	2019 Grid Modernization Annual Report
Exhibit ES-RWF/JGG	Joint Direct Testimony of Robert W. Frank and John G. Griffin
Exhibit ES-JGG-1	Capital Authorization Policy
Exhibit ES-JGG-2	Summary of Costs by Investment Type
Exhibit ES-JGG-3	Summary of Retirements
Exhibit ES-JGG-4	Project Master Summary
Exhibit ES-JGG-5	Project Documentation (Confidential)
Exhibit ES-JGG-6a and 6b	O&M Invoices (Confidential)
Exhibit ES-RWF-1	Revenue Requirement Calculation
Exhibit ES-RWF-2	O&M Overhead Test
Exhibit ES-RWF-3	Bill Impacts

C. **2020 Grid Modernization Cost Recovery, D.P.U. 21-58**

Initial Filing

Exhibit ES-GAP/KMB	Joint Direct Testimony of Giuseppe A. Perniciaro and Kevin M. Boughan
Exhibit ES-GAP/KMB-1	2020 Grid Modernization Annual Report
Exhibit ES-JGG-1	Capital Authorization Policy
Exhibit ES-JGG-2	Summary of Costs by Investment Type
Exhibit ES-JGG-3	Summary of Retirements
Exhibit ES-JGG-4	Project Master Summary
Exhibit ES-JGG-5	Project Documentation (Confidential and CEII)
Exhibit ES-JGG-6	O&M Invoices (Confidential)
Exhibit ES-RWF-1	Revenue Requirement Calculation
Exhibit ES-RWF-2	O&M Overhead Test
Exhibit ES-RWF-3	Bill Impacts

Responses to Information Requests

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DPU-1-2
Att. DPU-1-2(a) through (f)
DPU-1-3

Att. DPU-1-3
DPU-1-4
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DPU-2-1

III. Grid Modernization Plan Annual Reports

A. 2018 Grid Modernization Plan Annual Report, D.P.U. 20-45

Initial Filing

2018 Grid Modernization Plan Annual Report
2018 Grid Modernization Plan Annual Report Attachment ES-1
2018 Grid Modernization Plan Annual Report Attachment SI-1
2018 Grid Modernization Plan Annual Report Attachment SI-2/SI-3
2018 Grid Modernization Plan Annual Report (Supplemental)
2018 Grid Modernization Plan Annual Report (Supplemental) Appendix 1

Responses to Information Requests

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DPU-AR-1-2
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DPU-AR-2-1
Att. DPU-AR-2-1
DPU-AR-2-2
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B. 2019 Grid Modernization Plan Annual Report, D.P.U. 20-46

Initial Filing

2019 Grid Modernization Plan Annual Report
2019 Grid Modernization Plan Annual Report Appendix 1
2019 Grid Modernization Plan Annual Report Attachment ES-1
2019 Grid Modernization Plan Annual Report Attachment 2019 SI-1
2019 Grid Modernization Plan Annual Report Attachment 2019 SI-2/SI-23
2019 Grid Modernization Plan Annual Report Attachment EV Exhibit 1
2019 Massachusetts Grid Modernization Program Evaluation Report

Responses to Information Requests

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DPU-AR-2-1
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C. <u>2020 Grid Modernization Plan Annual Report</u>, D.P.U. 21-30

<u>Initial Filing</u>

2020 Grid Modernization Plan Annual Report
2020 Grid Modernization Plan Annual Report Appendix 1
2020 Grid Modernization Plan Annual Report Appendix 1 (Revised)
2020 Grid Modernization Plan Annual Report Attachment ES-1
2020 Grid Modernization Plan Annual Report Attachment ES-2
2020 Grid Modernization Plan Annual Report Attachment 2020 SI-1
2020 Grid Modernization Plan Annual Report Attachment 2020 SI-2/SI-23
2020 Massachusetts Grid Modernization Program Evaluation Report

<u>Responses to Information Requests</u>

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DPU-1-5
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2022

2018-2021 GMP Term Report

EVERSOURCE ENERGY

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I. Overview

In October 2012, the Department of Public Utilities (the "Department") initiated a wide-ranging and comprehensive investigation into the modernization of the Massachusetts electric grid. Modernization of the Electric Grid, D.P.U. 12-76 (2012). NSTAR Electric Company d/b/a Eversource Energy ("Eversource" or the "Company")[1] was an active and engaged partner in the Department's long-running investigation, bringing its expertise and innovation to bear on the effort. Eversource has always been, and continues to be, at the forefront of implementing technologies to further improve service to customers and lessen/mitigate the impact of outages on customers. The Department's Grid Modernization investigation enabled the Company to further expand its efforts on behalf of its customers and in making significant strides to achieve critical Massachusetts energy and environmental policies.

Over the course of several orders incorporating Eversource and other stakeholder input, the Department set out a Grid Modernization framework for Eversource, along with Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid") and Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil")(collectively, the "Distribution Companies"), to develop and invest in an innovative and comprehensive Distribution Company-specific Grid Modernization Plans ("GMPs") designed to advance achievement in four grid modernization objectives, specifically to: (1) reduce the effect of outages; (2) optimize demand, including reducing system and customer costs; (3) integrate distributed resources; and (4) improve workforce and asset management.[2]

Consistent with the directives set out in the Department's various D.P.U. 12-76 orders, on August 19, 2015, Eversource filed its first GMP. The Department conducted a lengthy and thorough investigation of the Company's GMP. On May 10, 2018, the Department issued an order approving in part and modifying in part the Company's GMP. NSTAR Electric Company d/b/a Eversource Energy d/b/a Eversource Energy, D.P.U. 15-122 (2018) ("D.P.U. 15-122"). In its order, the Department approved the Company's proposed grid-facing grid modernization investments, as well as a three-year (2018-2020) budget of $133 million to undertake the approved investments. D.P.U. 15-122, at 172-173, 186-187. The Department also determined that it was appropriate for Eversource to recover the costs of its energy storage demonstration projects and

[1] On December 31, 2017, Western Massachusetts Electric Company ("WMECO") was merged with and into NSTAR Electric Company ("NSTAR Electric"), with NSTAR Electric as the surviving entity pursuant to the Department's approval in D.P.U. 17-05 under G.L. c. 164, § 96. D.P.U. 17-05, at 36-44. Beginning January 1, 2018, the legal name of Eversource Energy's electric distribution company in Massachusetts is NSTAR Electric Company d/b/a Eversource Energy.

[2] The Department refined the grid modernization objectives in its order on the Distribution Companies' 2018-2020 GMPs, with the following established as the final objectives: (1) optimize system performance (by attaining optimal levels of grid visibility, command and control, and self-healing); (2) optimize system demand (by facilitating consumer price-responsiveness); and (3) interconnect and integrate distributed energy resources ("DER"). D.P.U. 15-122, at 106.

its electric vehicle ("EV") infrastructure program, approved in the Company's 2017 base distribution rate case, D.P.U. 17-05, through its targeted grid modernization cost recovery mechanism ("Grid Modernization Factor" or "GMF"). The total preauthorized amount for the Company's EV Infrastructure Program under D.P.U. 17-05 was $45 million. D.P.U. 15-122, at 35, fn. 21; D.P.U. 17-05, at 501-502. The total approved budget for the two energy storage demonstration programs was $55 million. D.P.U. 17-05, at 470.

As part of its ongoing review of Eversource's 2018-2020 and future GMPs, the Department required the Company to file annual GMP progress reports detailing its performance under the GMP during the relevant year ("Grid Modernization Annual Report" or "Report"). D.P.U. 15-122, at 112. The Company is required to report on its performance under the statewide and Eversource-specific infrastructure and performance metrics. The Department stamp approved the Company's performance metrics on July 25, 2019.

On May 12, 2020, the Department issued a decision extending the 2018-2020 GMP through December 31, 2021 to provide the Distribution Companies with the flexibility to adjust their respective GMPs through 2020 and reschedule any planned deployments that were delayed through 2021 due to COVID-19, or other factors. Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy for Approval by the Department of Public Utilities of their Grid Modernization Plan, D.P.U. 15-122-D, at 4 (2020) ("D.P.U. 15-122-D"). In its decision, the Department stated that, if the Distribution Companies experienced budget constraints related to authorized GMP investments as a result of the extension, they were authorized to petition the Department for an expansion of the Department-approved 2018-2020 GMP budget. D.P.U. 15-122-D at 7. Additionally, the Department required the Distribution Companies to file (1) an annual grid modernization report for calendar year 2020 on or before April 1, 2021; and (2) a grid modernization term report for calendar years 2018 through 2021 on or before April 1, 2022. Id. at 4, fn. 3.

On July 1, 2020, Eversource petitioned the Department requesting authorization for a budget extension of $56 million for the 2018-2021 GMP term, apportioned within the five investment categories previously authorized by the Department for Advanced Sensing, Automated Feeder Reconfiguration, Urban Underground Automation, Distribution System Network Operator and Communications. NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 20-74, 2020 Grid Modernization Program Extension and Funding Report at 6. In support of its petition, the Company noted that it expected to successfully complete its authorized 2018–2020 GMP by the end of 2020, having met or exceeded most targets and demonstrated progress relative to many of the ongoing metrics of grid modernization value and performance (id. at 5). The Company also requested approval of a budget authorization of $10 million to support and continue the approved EV Infrastructure Program through the end of 2021, as well as $3 million to continue the Energy Storage Program with engineering of incremental projects focused on the integration of distributed energy resources ("DER") in southeastern Massachusetts (id. at 6).

Following its investigation, the Department approved, with certain modifications, the Company's petition. D.P.U. 20-74, at 41-42. Therefore, combined with the initial authorized spending of $133 million in the five grid modernization categories for grid-facing investments, the total authorized spending for the 2018-2021 grid modernization investments is $199 million. Id.; D.P.U. 15-122, at 107-108.

After the May 10, 2018 issuance of the original D.P.U. 15-122 order, the Department conducted a sub-proceeding designed to formalize the contents and form of the Grid Modernization Annual Reports, including the development of templates to comprehensively and clearly provide data demonstrating the Company's annual progress under its GMP. When the Company submitted its 2018 Annual Report, the Grid Modernization Annual Report Templates had not yet been finalized. Accordingly, the Department directed Eversource and the other Distribution Companies to file, by May 1, 2019, a narrative detailing their performance under their respective 2018 GMPs. D.P.U. 15-122, March 29, 2019 Memorandum at 2. The Company filed this narrative on May 1, 2019.

On December 6, 2019, following a stakeholder comment period and a comprehensive technical conference to discuss the form and content of the Grid Modernization Annual Reports, the Department issued its order on the templates and the information required for the Annual Reports. NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 15-122-C (2019) ("D.P.U. 15-122-C"). Consistent with the Department's directives in the D.P.U. 15-122-C order, the Company submitted a supplemental 2018 Annual Report on January 31, 2020 to conform to the Annual Report template contemplated in the order. On April 1, 2020, consistent with the revised template, the Company filed its 2020 Grid Modernization Annual Report. On April 14, 2020, the Department issued a memorandum docketing the Company's 2018 Grid Modernization Annual Reports as D.P.U. 20-45 and the 2019 Grid Modernization Annual Reports as D.P.U. 20-46. D.P.U. 15-122, April 14, 2020 Memorandum at 3.

On March 11, 2021, the Department issued a memorandum regarding additional revisions to the Grid Modernization Annual Report templates to ensure consistent reporting of information and data among the Distribution Companies. D.P.U. 21-30, March 11, 2021 Memorandum at 2. Consistent with the Department's directives in D.P.U. 15-122-C and D.P.U. 15-122-D, as well as the Department's most recent memorandum, Eversource filed its 2020 Grid Modernization Annual Report on April 1, 2021. The Department docketed the Company's 2020 Grid Modernization Annual Report as D.P.U. 21-30.

Subsequently, on October 25, 2021, the Department issued a memorandum setting forth the proposed form and content of the Grid Modernization Term Report and solicited written comment on the proposed Grid Modernization Term Report Narrative Outline and data reporting template. D.P.U. 21-116, October 25, 2021 Memorandum at 2. The Department requested initial comments by November 18, 2021 and reply comments by January 6, 2022. Id. The Distribution Companies submitted initial comments on November 18, 2021 indicating they did not have any proposed edits to the Department's proposed form and content of the Grid Modernization Term Reports. D.P.U. 21-116, Distribution Companies' Initial Comments (November 18, 2021). There were no other comments filed. On February 15, 2022, the Department issued a memorandum finalizing the proposed Grid Modernization Term Report Narrative Outline and data reporting. D.P.U. 21-116, February 15, 2022 Memorandum. The Department prescribed April 1, 2022 for the Distribution Companies to submit their Grid Modernization Term Report that documents each Distribution Companies' performance during the entirety of the term. Id. at 2. The Department further docketed the Company's Grid Modernization Term Report as D.P.U. 22-40. Id. In accordance with the Department's February 15, 2022 Memorandum, the Company hereby submits its 2018-2021 Grid Modernization Term Report.

A. Term Progress Toward Grid Modernization Objectives

Eversource's GMP was designed based on the three refined Department objectives: (1) optimize system performance (by attaining optimal levels of grid visibility, command and control, and self-healing); (2) optimize system demand (by facilitating consumer price-responsiveness); and (3) interconnect and integrate distributed energy resources ("DER"). D.P.U. 15-122, at 106. This section summarizes the Company's progress toward each objective. Additional details and benefit examples for each investment category are included in Section III of this report. Figure 1 below also illustrates the relationship between each investment category and each grid modernization objective.

Figure 1: Matrix of Grid Modernization Investment Categories and Objectives

	Grid Modernization Objectives:		
Investment Category	**Optimize System Performance**	**Optimize System Demand**	**Interconnect and Integrate DER**
Monitoring & Control (SCADA)	✓		✓
Distribution Automation	✓		
Volt-Var Optimization	✓	✓	✓
Advanced Distribution Management System (ADMS)	✓	✓	✓
Communications	✓		✓
Electric Vehicles			✓
Energy Storage	✓	✓	✓

1. Optimize system performance (by attaining optimal levels of grid visibility, command and control, and self-healing)

The Company has made substantial investments during the GMP that are expected to help optimize system performance. Investments within the Monitoring and Control ("M&C"), Distribution Automation ("DA"), Volt-Var Optimization ("VVO"), Advanced Distribution Management System ("ADMS"), and Communications will contribute toward this objective.

The M&C investment category includes microprocessor relays, 4kV circuit breaker SCADA, recloser SCADA, padmount switch SCADA, and power quality monitors. At the end of 2021, the Company provided visibility and automation to over 250 substation feeder breakers through the microprocessor relay and 4kV circuit breaker SCADA programs. The addition of these advanced relays provides the optimal level of visibility, command, and control for the affected feeders. In addition to collecting real-time loading data that is transmitted back to a centralized energy control system, these relays allow for remote operations such as application of fast-trip and lock-out settings for worker safety or changes in protection settings. This program has resulted in significant progress towards achieving optimal levels of visibility and control at all feeders in the Eversource territory. This progress was made at a pace that would not have been possible absent the grid modernization program.

Further gains were made by adding remote visibility and control to over 200 existing automation devices through the recloser SCADA, padmount switch SCADA, and network protector SCADA programs. With cost-effective upgrades, these formerly partially automated devices are now fully automated and contribute to the optimization of power flows on the system. This program was completed in 2021, having achieved its intended purpose of eliminating the addressable population of partially automated field devices across the system.

In 2021, the Company added a new grid modernization investment to its portfolio. The power quality program added high-fidelity metering at substations serving customers sensitive to power quality events. It is becoming increasingly clear that the modern grid must be characterized by a higher degree of power quality to meet the needs of customers with sensitive electronic equipment. The benefits of automation in terms of reducing sustained outages is well known. The impact of automation in terms of power quality requires another level of visibility, command, and control. The enhanced monitoring deployed at one substation has proven successful in proving this next level of visibility required to identify potential mitigation opportunities. Optimally, this technology will be deployed at all substations serving large customers with sensitive loads. The 2022-2025 GMP has proposed to add this functionality at four additional, key substations. Further deployments will be built into other GMP proposals or the Company's base capital programs.

The DA investment category includes overhead DA and 4kV oil switch replacements. At the end of 2021, the Company had increased visibility by installing over 380 overhead DA devices and completing over 170 4kV oil switch replacements. These programs will improve the self-healing capacity of both the overhead and underground system. In combination with fault location, isolation, and service restoration logic, the grid will sense the existence of a fault, automatically isolate it to the smallest possible segment and then restore service to all customers outside the faulted zone with supply from alternate sources. This capability makes the grid flexible and dynamic with the goal of maximizing system safety and reliability. The optimal penetration of overhead and underground DA devices is largely a function of sectionalization, defined as the number of customers between fully automated devices. As a result of the 2018-2021 GMP, the Company has attained the optimal level of sectionalization in its overhead system. Although overhead DA devices will be deployed as part of the Company's base capital plan in the future for specific needs, the step-change in sectionalization enabled by the grid modernization program has resulted in the required level of automation needed to support the modern grid. Similarly, the deployment of underground switches to replace antiquated oil switches has set the Company on a path to achieve its desired end-state of a fully automated underground system. Existing oil switch replacement programs will drive to this conclusion with no further need to include these switches in the Company's grid modernization portfolio.

The Company's VVO program supports all three grid modernization objectives. Prior to the VVO program the Company's substation transformer load tap changers, voltage regulators and capacitor banks were partially automated with limited remote control capability. The VVO program deployed fully automated devices that provide enhanced levels of visibility, command, and control required to flatten and reduce voltage profiles along an entire feeder in combination with automated logic provided by VVO software. This level of visibility and control also supports system operators' need to manage two-way power flows in areas with high Distributed Energy Resources ("DER") penetration.

In addition to automated devices capable of remote command and control, targeted deployment of line sensors provides visibility out towards the grid edge. Line sensors installed as a part of the VVO program are required to ensure voltage remains in its acceptable range out to the grid edge in pursuit of improved system efficiency. In addition to VVO line sensors, the Company also deployed over 250 grid monitoring line sensors to add visibility in areas of high DER penetration.

With these advanced sensors and automation devices, the increasingly modern grid will provide much improved situational awareness for system operators, better positioning them to adapt and respond to real-time conditions. Device deployments during the 2018-2021 GMP also support optimized self-healing schemes of the Company's future Distribution Management System ("DMS").

It is impossible to contemplate a modern grid that does not rely on a robust, high bandwidth, high speed communication system to enable real-time, automated communications to end use equipment. In fact, it is important to consider the degree to which a strong communications infrastructure builds a foundation for all grid investments. As an enabling technology for the modern grid, system performance was also optimized through the Company's Communications investments. Upgraded node locations have provided increased and more comprehensive coverage in areas where coverage was otherwise limited previously.

Progress made towards placing the Company's energy storage system ("ESS") and DMS in service through the end of 2021 has established a foundation for these technologies to further optimize system performance once completed in the 2022-2025 GMP term.

2. Optimize system demand (by facilitating consumer price-responsiveness)

Optimization of system demand was achieved as a result of the VVO and ADMS/Advanced Load Flow (“ALF”) programs.

The use of VVO to achieve multiple grid modernization investment objectives remains extremely compelling. The benefits of improving the efficiency of voltage and reactive power flow include cost savings associated with reduced energy consumption, reduced peak demand, reduced line losses and the associated reduction in carbon emissions. Preliminary results of the VVO program as measured in 2021 have been in line with expectations for a 2.2 percent reduction in end-use energy consumption for customers on affected circuits. With respect to peak demand, the Company expects to confirm its projection of achieving an approximately 0.6 percent reduction in peak load for every percent reduction in voltage for the feeders on which VVO is deployed. Although the Company has remained conservative in its deployment of VVO to date in order to ensure no adverse impacts to customers served by VVO feeders, further optimization of the VVO logic has the potential to drive additional savings in energy and demand.

As a result of the ALF program, the Company was able to place Synergi Electric software in service enabling load flow engineering analysis for all feeders in Massachusetts. With enhancements made to Synergi Electric in 2021, all feeders have achieved “ALF fully automated” status. The load flow analysis performed by system planners using the tool is providing additional insights into opportunities to deploy cost-effective system upgrades in a way that manages peak load demands. This capability is increasingly important with the increased penetration of electric vehicles. The ALF Advanced Forecasting project initiated in 2021, will provide further increases in load flow analysis capabilities reflecting the substantial impact of DER on the system.

Progress made towards placing the Company’s energy storage system (“ESS”) and DMS in service through the end of 2021 has established a foundation for these technologies to further optimize system demand and reduce peak load once completed in the 2022-2025 GMP term.

3. Interconnect and integrate DER

Given the growing imperative to integrate distributed clean energy solutions, Eversource is actively focused on achieving the Department’s grid modernization objective of facilitating the interconnection of DER and to integrating these resources into the Company’s planning and operations processes. Gains in pursuit of this objective have resulted from the Company’s M&C, VVO, ADMS and Communications programs.

Increased visibility, command, and control enabled by M&C programs is providing system operators with the information needed to understand and act on emerging issues, including reverse flow overload and high voltage concerns in areas of high solar penetration. Data on status and condition provided by devices deployed in this category will support improvements in the DMS optimal power flow capability that will ultimately be integrated into the Company's Distribution Energy Management System ("DERMS") used to support the use of DER as grid assets.

One of the objectives of the VVO program is to ensure the distribution voltages remain within prescribed ranges and are not fluctuating rapidly as additional DER, characterized by intermittent output, is added to the system. In implementing its 2018-2021 GMP, the Company identified feeders with relatively high penetrations of both behind the meter and stand-alone solar facilities. This is helping to provide insight into how VVO technology can be used to increase hosting capacity.

The Company's ALF program incorporates system characteristics, load information and DER into a planning load flow that provides planning engineers a tool that can optimize system design in the presence of high penetrations of solar and other DER. System planners will also use the advanced load flow tool to study interconnection of new DER facilities. The load flow tool is expected to reduce study time and enable more sophisticated contingency analysis. Investment in advanced load flow capability has set the stage for increasing capabilities relative to hosting capacity maps, enhanced DER forecasting and a distribution management system ("DMS") that will provide load flow capabilities to the Company's system operators giving them enhanced visibility and control of the distribution system as it becomes more complex, dynamic, and modular.

As an enabling technology for the modern grid, DER integration has also improved due to the Company's Communications investments. Upgraded node locations have provided increased and more comprehensive coverage in areas where coverage was otherwise limited previously.

B. Summary of Term Grid Modernization Deployment (Actual v. Planned)

Figure 2 Unit Deployment (# of Units)

Investment Category	Preauthorized Device Type	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2018-2021 Actual	2018-2021 Projection*	% Difference
Monitoring & Control (SCADA)	Microprocessor Relay	10	87	83	22	202	237	-15%
	4kV Circuit Breaker SCADA	0	16	38	0	54	67	-19%
	Recloser SCADA	15	19	25	0	59	59	0%
	Padmount Switch SCADA	3	41	15	0	59	59	0%
	Network Protector SCADA	0	0	83	8	91	104	-13%
	Power Quality Monitors	0	0	0	39	39	34	15%
Distribution Automation	OH DA w/o Ties	25	148	70	91	334	343	-3%
	OH DA w/Ties	0	45	8	0	53	53	0%
	4kV Oil Switch Replacement	0	89	48	35	172	172	0%
	4kV AR Loop	0	17	1	0	18	34	-47%
Volt-Var Optimization	VVO - Regulators	0	69	27	1	97	144	-33%
	VVO - Capacitor Banks	0	71	3	0	74	106	-30%
	VVO - LTC Controls	4	4	0	0	8	12	-33%
	VVO - Line Sensors	0	189	0	16	205	229	-10%
	VVO - IT Work	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Microcapacitors	0	0	99	55	154	299	-48%
	Grid Monitoring Line Sensors	0	0	111	151	262	411	-36%
Advanced Distribution Management System (ADMS)	Advanced Load Flow	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	GIS Survey (Expense)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Dist. Management System	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Forecasting Tool	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Synergi Upgrades	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	PI Asset Framework	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Communications	Numbers of Nodes	0	4	4	2	10	14	-29%
	Miles of Fiber	0	0	0	2	2	0	N/A
Electric Vehicles	Electric Vehicles	12	112	181	150	455	500	-9%
Energy Storage	Martha's Vineyard	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Provincetown	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Total Units	69	911	796	572	2,348	2,877	

* Information contained within the *2018-2021 Projection* column was based on the projections made as part of the 2020 GMP Annual Report

C. Summary of Term Spending (Actual v. Planned)

As discussed in prior Annual Reports and as can be found in Section II of this Term Report, the Company has gone to great lengths to ensure financial accuracy. This level of diligence allowed the team to continuously evaluate actual spending, finalized and proposed budgets, and the Department-approved spending caps. As seen in Figure 3, Figure 4, Figure 5 and Figure 6 below, there are many investment types in which the actuals deviate from the projections. These deviations will be explained further in Section III of this Term Report. However, it should be noted that from the outset, the Company made conscious decisions when analyzing spending and deciding to shift funds from one investment, to another. The Company's general approach was to retain movement of funds within the same investment category but there were times when spending and budgets, after review on a holistic level, required funds to be shifted among categories for an effective deployment. Based on its rigorous oversight and cost control, the Company has, for the SCADA, DA, VVO, ADMS, Communications and Electric Vehicles investment categories, remained below the Department-authorized spending cap of $299 million. As detailed in the 2020 GMP Annual Report, the Company ultimately determined that it was prudent to cancel the Martha's Vineyard energy storage project due to changed circumstances. This decision, as well as additional information on the Outer Cape energy storage project, is addressed later in this report.

Figure 3 Capital Spending by Pre-Authorized Device Type ($)

Investment Category	Preauthorized Device Type	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2018-2021 Actual	2018-2021 Projection*	% Difference
Monitoring & Control (SCADA)	Microprocessor Relay	3,363,115	14,991,129	11,737,080	4,267,995	34,359,319	41,351,117	-17%
	4kV Circuit Breaker SCADA	83,747	4,085,366	11,763,300	2,326,928	18,259,341	19,932,413	-8%
	Recloser SCADA	963,353	888,665	1,533,849	(397)	3,385,470	3,385,867	0%
	Padmount Switch SCADA	105,723	615,476	285,790	(226)	1,006,763	1,006,989	0%
	Network Protector SCADA	-	871,602	559,572	2,784	1,433,958	2,148,174	-33%
	Power Quality Monitors	-	-	214,937	496,048	710,985	1,170,506	-39%
Distribution Automation	OH DA w/o Ties	2,267,503	12,069,703	3,838,524	6,533,425	24,709,155	26,175,729	-6%
	OH DA w/Ties	-	2,797,738	455,052	3,026	3,255,816	3,252,790	0%
	4kV Oil Switch Replacement	932,307	13,881,098	9,189,867	6,191,485	30,194,757	29,003,272	4%
	4kV AR Loop	-	891,645	569,292	835,732	2,296,669	2,460,937	-7%
Volt-Var Optimization	VVO - Regulators	-	2,375,328	1,631,621	(20,208)	3,986,740	6,061,931	-34%
	VVO - Capacitor Banks	-	2,548,685	311,402	711,710	3,571,796	2,860,086	25%
	VVO - LTC Controls	377,157	1,044,867	30,253	125	1,452,402	2,397,267	-39%
	VVO - Line Sensors	-	678,782	556,053	197,862	1,432,698	1,234,836	16%
	VVO - IT Work	-	1,159,861	1,468,664	48,755	2,677,280	2,628,525	2%
	Microcapacitors	-	-	750,675	364,441	1,115,116	2,250,675	-50%
	Grid Monitoring Line Sensors	-	-	-	592,053	592,053	1,500,000	-61%
Advanced Distribution Management System (ADMS)	Advanced Load Flow	-	2,775,876	6,033,013	153,907	8,962,796	8,808,889	2%
	GIS Survey (Expense)	-	-	-		-	-	N/A
	Dist. Management System	-	-	-	1,596,259	1,596,259	8,000,001	-80%
	Forecasting Tool	-	-	-	1,843,343	1,843,343	3,246,003	-43%
	Synergi Upgrades	-	-	-	942,445	942,445	767,003	23%
	PI Asset Framework	-	-	-	1,076,564	1,076,564	986,498	9%
Communications	Numbers of Nodes	-	522,256	1,105,885	778,560	2,406,701	5,734,556	-58%
	Miles of Fiber	-	309,896	255,618	581,155	1,146,668	1,565,513	-27%
Electric Vehicles	Electric Vehicles	2,859,831	10,979,264	18,075,501	12,842,659	44,757,255	50,916,596	-12%
Energy Storage	Martha's Vineyard	958,654	1,305,943	945,977	(3,210,574)	-	3,598,506	-100%
	Provincetown	624,690	1,722,882	15,362,063	22,350,958	40,060,593	45,996,635	-13%
	Total Capital Spending	12,536,080	76,516,061	86,673,988	61,506,814	237,232,943	278,441,314	-15%

* Information contained within the *2018-2021 Projection* column was based on the projections made as part of the 2020 GMP Annual Report

Figure 4 Capital Spending by Investment Category ($)

Investment Category	Charge Types	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2018-2021 Actual
Monitoring & Control (SCADA)	Labor	324,095	2,879,931	3,350,773	797,313	7,352,113
	Non Labor	4,191,844	18,572,307	22,743,754	6,295,818	51,803,723
	Total	**4,515,939**	**21,452,238**	**26,094,528**	**7,093,131**	**59,155,836**
Distribution Automation	Labor	356,683	3,759,168	2,234,191	1,890,236	8,240,279
	Non Labor	2,843,127	25,881,015	11,818,544	11,673,433	52,216,119
	Total	**3,199,810**	**29,640,184**	**14,052,735**	**13,563,669**	**60,456,397**
Volt-Var Optimization	Labor	38,122	297,296	271,216	117,708	724,342
	Non Labor	339,035	7,510,227	4,477,453	1,777,032	14,103,746
	Total	**377,157**	**7,807,523**	**4,748,668**	**1,894,740**	**14,828,088**
Advanced Distribution Management System	Labor	-	207,614	347,994	266,140	821,747
	Non Labor	-	2,568,262	5,685,019	5,346,380	13,599,661
	Total	**-**	**2,775,876**	**6,033,013**	**5,612,520**	**14,421,409**
Communications	Labor	-	119,174	136,735	253,710	509,619
	Non Labor	-	712,977	1,224,768	1,106,006	3,043,750
	Total	**-**	**832,151**	**1,361,503**	**1,359,716**	**3,553,370**
Electric Vehicles	Labor	109,783	525,730	547,566	624,552	1,807,631
	Non Labor	2,750,049	10,453,534	17,527,935	12,218,103	42,949,621
	Total	**2,859,831**	**10,979,264**	**18,075,501**	**12,842,655**	**44,757,252**
Energy Storage	Labor	162,452	257,082	441,371	802,058	1,662,964
	Non Labor	1,420,891	2,771,742	15,866,668	18,338,325	38,397,627
	Total	**1,583,343**	**3,028,824**	**16,308,040**	**19,140,383**	**40,060,590**
Total Grid Modernization	Labor	991,134	8,045,996	7,329,847	4,751,718	21,118,695
	Non Labor	11,544,945	68,470,065	79,344,141	56,755,096	216,114,247
	Total	**12,536,080**	**76,516,061**	**86,673,988**	**61,506,814**	**237,232,942**

Figure 5 O&M Spending by Investment Category ($)

Investment Category	Charge Types	2018 Actual	2019 Actual	2020 Actual	2021* Actual	2018-2021 Actual
Monitoring & Control (SCADA)	Internal O&M (labor-related)	-	-	-	-	-
	External contractor expense	-	1,108	34,251	5,163	40,522
	Total	**-**	**1,108**	**34,251**	**5,163**	**40,522**
Distribution Automation	Internal O&M (labor-related)	-	-	-	-	-
	External contractor expense	-	161,672	108,781	242,314	512,766
	Total	**-**	**161,672**	**108,781**	**242,314**	**512,766**
Volt-Var Optimization	Internal O&M (labor-related)	-	-	-	-	-
	External contractor expense	-	161,671	401,639	42,979	606,288
	Total	**-**	**161,671**	**401,639**	**42,979**	**606,288**
Advanced Distribution Management System	Internal O&M (labor-related)	-	-	-	-	-
	External contractor expense	706,268	5,355,497	326,382	1,833,854	8,222,000
	Total	**706,268**	**5,355,497**	**326,382**	**1,833,854**	**8,222,000**
Communications	Internal O&M (labor-related)	-	-	-	-	-
	External contractor expense	-	-	-	40	40
	Total	**-**	**-**	**-**	**40**	**40**
Electric Vehicles	Internal O&M (labor-related)	-	-	-	-	-
	External contractor expense	17,223	735,630	1,230,751	749,799	2,733,403
	Total	**17,223**	**735,630**	**1,230,751**	**749,799**	**2,733,403**
Energy Storage	Internal O&M (labor-related)	104,708	-	-	-	104,708
	External contractor expense	-	-	167,168	2,524,628	2,691,795
	Total	**104,708**	**-**	**167,168**	**2,524,628**	**2,796,504**
Admin & Regulatory	Internal O&M (labor-related)	-	402,346	348,523	319,062	1,069,931
	External contractor expense	-	189,338	192,710	194,836	576,883
	Total	**-**	**591,684**	**541,233**	**513,898**	**1,646,814**
Total Grid Modernization	Internal O&M (labor-related)	104,708	402,346	348,523	319,062	1,174,639
	External contractor expense	723,490	6,604,915	2,461,682	5,593,611	15,383,698
	Total	**828,199**	**7,007,261**	**2,810,205**	**5,912,673**	**16,558,338**

*2021 O&M spending will be finalized at the time of the Company's Grid Modernization Factor ("GMF") filing due to be filed by May 15th, 2022

Figure 6 Capital and O&M by Investment Category ($)

Investment Category	2018 Actual	2019 Actual	2020 Actual	2021* Actual	2018-2021 Actual
Monitoring & Control (SCADA)	4,515,939	21,453,347	26,128,779	7,098,294	59,196,358
Distribution Automation	3,199,810	29,801,855	14,161,516	13,805,983	60,969,164
Volt-Var Optimization	377,157	7,969,194	5,150,307	1,937,719	15,434,376
Advanced Distribution Management System (ADMS)	706,268	8,131,373	6,359,395	7,446,374	22,643,409
Communications	-	832,151	1,361,503	1,359,756	3,553,410
Electric Vehicles	2,877,054	11,714,894	19,306,252	13,592,454	47,490,654
Energy Storage	1,688,052	3,028,824	16,475,207	21,665,011	42,857,094
Admin & Regulatory	-	591,684	541,233	513,898	1,646,814
Total Grid Modernization	**13,364,278**	**83,523,321**	**89,484,192**	**67,419,488**	**253,791,280**

*2021 O&M spending will be finalized at the time of the Company's Grid Modernization Factor ("GMF") filing due to be filed by May 15th, 2022

D. Significant Term Cost & Unit Variances

The Company's actual execution plan for the 2018-2021 GMP has many individual investment variances, often with the Company exceeding the original unit commitments. This section is meant to acclimate the reader to the programmatic changes that occurred, as they relate to the original filings and orders (D.P.U. 15-122 and D.P.U. 20-74). Many of the variances were due to the ever-changing condition of the electric distribution system, changes in available technology, and increases in labor and equipment costs. In all these cases, and as discussed throughout this report, the Company worked diligently to ensure optimal deployment and customer benefit. In the few instances where there is work from 2021 that will carry over to 2022, the costs for these investments are evaluated and budgeted based on the 2018-2021 GMP preauthorized spending cap without the need for supplemental approval.

For the following sections, the Company will provide a summary of deployment and investment variances based on the total Department-approved values and actuals through the end of 2021. It also summarizes variances to the revised projections that were submitted in the 2020 GMP Annual Report. This section also includes the projected (2021 carry-over to 2022) values for any investments that were not completed by the end of 2021. See Section III for more detailed descriptions of cost and unit variances, including key drivers.

1. Monitoring & Control

- **Microprocessor Relay** – The original Department authorized device deployment and projected cost was 246 feeders and $37M, respectively. At term completion, 202 feeders have been commissioned and $34.4M has been spent. At the end of calendar year 2021, the Company is underrunning its estimates by 35 feeders and $7M, respectively. This was a result of the work requiring a 12-18 month timeline, which resulted in the projects being undertaken in early 2021, as opposed the originally anticipated fall of 2020 commencement. The units are scheduled for completion in 2022. Upon final completion of all work, including 2021 carry-over, the device deployment will be 237 feeders and the final costs will be at, or less than, $41.4M.

- **4kV Circuit Breaker SCADA** – The original Department authorized device deployment and projected cost was 55 feeders and $10M, respectively. At term completion, 54 feeders have been commissioned and $18.4M has been spent. At the end of calendar year 2021, the Company is underrunning by 13 feeders and $1.7M, respectively. This was a result of the work requiring a 12-18 month timeline, which resulted in the projects being undertaken in early 2021 consistent with the issuance of the order in D.P.U. 20-74, as opposed to the originally anticipated fall of 2020 commencement. The units and costs are scheduled for completion in 2022. Upon final completion of all work, including 2021 carry-over, the device deployment will be 67 feeders and the final cost will be at, or less than, $20M.

- **Recloser SCADA** – The original Department authorized device deployment and projected cost was 37 units and $2.4M, respectively. At term completion the device deployment and final costs are 59 units and $3.4M, respectively. The Company completed 22 (60 percent) additional units for $1M in additional cost. This is inclusive of performing full unit replacements as opposed to originally proposed radio-only additions.

- **Padmount Switch SCADA** – The original Department authorized device deployment and projected cost was 62 units and $0.8M, respectively. At term completion the device deployment and final costs are 59 units and $1M, respectively. The Company is three units under its original deployment proposal and is slightly higher in cost. The unit underrun is due to the Company exhausting all possible locations for deployment and the overrun in costs is due to the locational variation of work to be performed (i.e., the average installation costs was higher than expected).

- **Network Protector SCADA** – The original Department authorized device deployment and projected cost was 83 units and $5M, respectively. At term completion the device deployment and final costs are 91 units and $1.4M, respectively. The Company completed eight additional units for $2.8M less than the original deployment proposal. The final design selection for this program was significantly less costly than originally estimated, which allowed for the additional unit deployment while still retaining a net budget surplus. The Company had already reached its commitment of 83 units in 2020 and exceeded its commitment in 2021. Figure 2 and Figure 3, above, indicate a 13 percent underrun in units deployed and a 33 percent underrun in costs for the term because these values were based on the Company's more aggressive deployment plan, which did not come to fruition, due to an unexpected reconfiguration of the substation where the last Network Protector SCADA project was to take place. Section III contains additional detail regarding the Network Protector SCADA investment plan and deployment. The Company will not be deploying any additional network protector SCADA units because it has already exceeded the original commitment and the remaining substation for deployment will require additional, non-GMP work that will not be completed until a later date.

- **Power Quality Monitors** – The original Department authorized device deployment and projected cost was 34 feeders and $1.2M, respectively. At term completion, the device deployment and final costs are 39 feeders and $0.7M, respectively. The additional units were based on adding buss section relays to the program and the underrun in costs is due to a more efficient deployment of the nascent technology than expected.

4. Distribution Automation

- **Overhead Distribution Automation without Ties** – The original Department authorized device deployment and projected cost was 296 units and $27.4M, respectively. At term completion, 334 units have been commissioned and $24.7M has been spent. The Company met its commitment in 2021 but is reporting an underrun of nine units and $1.5M, respectively, which is based on the Company's additional deployments. The 9-unit underrun of the Company's more aggressive deployment target is based on a challenged resource load in the Southern region of the territory, where there was a significant amount of work for 2021 already in place, namely from the base capital planned work, and a shift in deployment of the Provincetown energy storage project. Upon final completion of all work, including 2021 carry-over, the device deployment will be 343 units and final costs will be at, or less than, $26.2M.

- **Overhead Distribution Automation with Ties** – The original Department authorized device deployment and projected cost was 38 units and $6.3M, respectively. At term completion, the device deployment and final costs are 53 units and $3.3M, respectively. The Company was able to reduce both the original average unit costs and install additional units due to identifying key circuit tie locations that required limited upgrades, other than the tie itself.

- **4kV Oil Switch Replacement** – The original Department authorized device deployment and projected cost was 105 units and $18.7M, respectively. At term completion, the device deployment and final costs are 172 units and $29M, respectively. This program had, on average, a slightly higher unit cost than originally proposed, but the Company made the decision to significantly exceed the original deployment commitment in order to advance this important initiative to both eliminate oil-filled equipment and to provide visibility, command and control of the devices in the field. As noted above, the deployment of the underground switches to replace antiquated oil switches has set the Company on a path to achieve its desired end-state of a fully automated underground system, with no further need to include replacement of these switches in the Company's grid modernization portfolio.

- **4kV Auto-Restoration Loop** – The original Department authorized device deployment and projected cost was 78 units and $4.3M, respectively. Early in the term, the Company reconfigured this program from the "4kV VFI Retrofit" program to the "4kV Auto-Restoration Loop" program, which also revised the method of measurement from "units" to "loops created." Based on these revisions, the original 78-unit Department commitment became obsolete. At the term completion, the 4kV AR Loop program was not successfully commissioned. There are a number of reasons for this situation that are explained in more detail in Section III.B. of this Term Report. The originally estimated cost for this program was $2.5M. The actual costs associated with this program are currently at $2.3M. Due to the commissioning challenges, and the advancement of other technology deployments within the GMP, the Company has made the decision to terminate the 4kV AR Loop program.

5. Volt-Var Optimization

- **VVO – Regulators** – The original Department authorized device deployment and projected cost was 144 units and $7.3M, respectively. At term completion, 97 units have been commissioned and $4.0M has been spent. At the end of calendar year 2021, the

Company is underrunning by three units and $0.5M, respectively. The significant reduction in total deployment, from 144 units to 100 units, is due to the reduced need for regulators, which was determined after the full engineering and design was completed. The underrun of three units for 2021 is due to a very lengthy equipment lead-time. There is the potential that the equipment lead may push the completion of regulator work into 2023. Upon final completion of all work, including 2021 GMP investment carry-over work to be completed in 2022, the device deployment will be 100 units and the final costs will be at, or less than, $4.5M.

- **VVO - Capacitor Banks** – The original Department authorized device deployment and projected cost was 106 units and $2.8M, respectively. At term completion, 74 units have been commissioned and $3.6M has been spent. At the end of calendar year 2021, the Company is underrunning by 32 units and overrunning the projection by $0.8M, respectively. The reduction in total deployment, 106 units to 99 units, is due to the reduced need for capacitors, which was determined after the full engineering and design was completed. The underrun in unit deployment is caused by a longer than expected material delivery and the vendor's delivery of incorrect equipment. The higher cost is due to the higher-than-expected average unit costs associated with installing and commissioning the system. The Company will complete the remaining 25 units in 2022. Upon final completion of all work, including 2021 GMP investment carry-over work to be completed in 2022, the device deployment will be 99 units and final costs will be at, or less than, $3.7M.

- **VVO - LTC Controls** – The original Department authorized device deployment and projected cost was 14 units and $0.7M, respectively. At term completion, including 2021 carry-over work, the device deployment and final costs will be eight units and $1.5M, respectively. The original deployment of 10 units set out in the Company's initial 2018-2020 GMP filed in D.P.U. 15-122 was significantly underbudgeted. This was due to the limited availability of historic costs, coupled with increased specialized external work force and equipment costs. The Company revised the average cost budgets in its D.P.U. 20-74 filing (four units). After final engineering and design were completed, only eight of 14 LTC controls units were required. There will be no further LTC controls installed as part of a future GMP.

- **VVO - Line Sensors** – The original Department authorized device deployment and projected cost was 180 units and $0.9M, respectively. At term completion, 205 units have been commissioned and $1.4M has been spent. After final engineering and design were completed, the system required more line sensors than anticipated. The remaining 20 units were not installed in 2021 due to equipment delivery delays and will be installed in

2022. Upon final completion of all work, including 2021 GMP investment carry-over work to be completed in 2022, the device deployment will be 225 units and the final costs will be at, or less than, $1.5M.

- **VVO - IT Work** – The original Department authorized projected cost was $6.7M, for the entire I.T. system integration. The VVO I.T. system was commissioned in 2020 for $2.7M. The primary drivers of the budget underrun were lower than expected software costs and implementation of a more efficient work plan for the model build process.

- **Microcapacitors –** The original Department authorized device deployment and projected cost was 299 units and $2.3M, respectively. At term completion, 154 units have been commissioned and $1.1M has been spent. At the end of calendar year 2021, the Company was underrunning by 145 units and on target for cost projections, respectively. The underrun in unit deployment was caused by vendor material delivery delays, which were not communicated until Q4, 2021. The Company will complete the remaining 145 units in 2022. Upon final completion of all work, including 2021 GMP investment carry-over work to be completed in 2022, the device deployment will be 299 units and the final costs will be at, or less than, $2.3M.

- **Grid Monitoring Line Sensors** – The original Department authorized device deployment and projected cost was 411 units and $1.4M, respectively. At term completion, 262 units have been commissioned and $0.6M has been spent. At the end of calendar year 2021, the Company is underrunning by 149 units and on target for cost projections, respectively. The underrun in unit deployment was caused by longer than expected equipment deliveries, which then caused a conflict in resource availability. The Company will complete the remaining 149 units in 2022. Upon final completion of all work, including 2021 GMP investment carry-over work to be completed in 2022, the device deployment will be 410 units and the final costs will be at, or less than, $1.5M.

6. Advanced Distribution Management System

- **ALF** – The original Department authorized projected cost was $9M for the entire I.T. system integration. The ALF system was commissioned in 2020 for $8.8M. The "Synergi Upgrades" project, discussed below, will be an enhancement to the ALF to allow for fully automated model builds.

- **Geographic Information System ("GIS") Survey (Expense)** - The original Department authorized projected cost for the EMA and WMA GIS Surveys was $8.8M. At term completion, $8.2M has been spent. The EMA GIS Survey was completed in 2019. The WMA GIS Survey was 75 percent complete at the end of 2021. As of the filing of this Term Report, the WMA GIS Survey has been completed and the final costs are expected to be

$2.6M pending reconciliation with the GMF to be filed at a later date. Total program costs are expected to be $8.6M.

- **DMS** – The original Department authorized projected cost was $10M for the entire 2018-2022 GMP, for the commencement of the project. At the time of the initial D.P.U. 15-122 order, issued in May 2018, the Company determined that it could not commence deployment of the DMS because of a technology dependency on the implementation of the Company's eECS, which was not place into the service until Q4-2020. This dependency explains why the Company did not expend the preauthorized $2M on DMS. As part of the D.P.U. 20-74 order, the Department approved the Company's proposal to move forward with the commencement of the DMS implementation, which it has done. The DMS implementation will be for the Company's MA service territory and is expected to be completed by end of 2023. The timeframe associated with starting a project of this size and complexity had a long initiation period. The Company's project approval policy requires a detailed assessment and description of the work to take place and a cost estimate that is broken down into several more granular pieces. This required the engagement of many cross-departmental internal personnel and external vendors to develop the project scope and cost. After that exercise was completed, presentation and approval of the project was required up through the Company's President and CEO. This process shifted the internal project approval to late Q2 of 2021. The Company has since spent $1.6M and is on track for deployment in 2023. Total DMS deployment is expected to cost $24M and work on this investment will take place during the Company's 2022-2025 GMP. $24M is the expected total deployment, inclusive of the $8M preauthorized amount from D.P.U. 20-74, of the DMS across the Company's Massachusetts territory.

- **Forecasting Tool** – The original Department authorized projected cost was $3.3M for development and deployment of an advanced load forecasting system. Upon issuance of the order in D.P.U. 20-74, the timeframe associated with starting this project shifted the internal project approval to late Q2 of 2021. The Company has spent $1.8M in 2021 and will continue the work to commission the system in 2022, for approximately $5.5M. The cost increase is associated with licensing costs for additional software required for generating scenarios and forecasts. Support for the cost increase associated with this project will come from the budget underrun in the DMS project.

- **Synergi Upgrades** – The original Department authorized projected cost was $0.7M for deployment of a Synergi upgrade that will complement the Company's existing ALF system by fully automating the model-builds for hosting capacity maps. This project was commissioned in 2021. Total cost for the project is $0.9M and the cost increase was due to the enhancements to the graphical user interface determined to be necessary as they improved usability.

- **PI Asset Framework** – The original Department authorized projected cost was $1M for deployment of software that would enable efficient exporting of substation interval data for advanced analysis as well as restructuring of the data tags to provide uniformity across all stations. This project is substantially completed but will not be commissioned until 2022. Total cost for the project is expected to be $1.3M. The cost increase was caused by additional work required to provision and secure the cloud-based environment where data will be exported.

7. Communications

- **Numbers of Nodes** – The original Department authorized device deployment and projected cost was 14 units and $6M, respectively. At term completion 10 units have been commissioned and $2.4M has been spent. At the end of calendar year 2021, the Company is underrunning by four units and on target for cost projections, respectively. The underrun in unit deployment was caused by challenges with integrating a new radio frequency into the Company's front end processors, which took longer than expected. The Company will complete the remaining five (four to meet commitment plus one additional) units in 2022. Upon final completion of all work, including 2021 GMP investment carry-over work to be completed in 2022, the device deployment will be 15 units and the final costs will be at, or less than, $5.7M.

- **Miles of Fiber** – The original Department authorized miles of fiber deployment and projected cost was 250 miles of fiber and $17M, respectively. In mid-2019, the Company determined that there was not a cost-effective method to deploy the committed quantity of fiber and therefore made the decision to terminate the program and redeploy the funds to other investments. The Company determined that a select group of locations to install and commission fiber at substations that have received other GMP upgrades was prudent. At term completion, ~2 miles have been commissioned and $1.2M has been spent. At the end of calendar year 2021, the Company commissioned two of the five locations and will commission the remaining three locations in 2022. Upon final completion of all work, including 2021 GMP investment carry-over work to be completed in 2022, the device deployment will be ~2 miles of fiber at five locations, and the final costs will be at, or less than $1.6M.

8. Electric Vehicles

- **Electric Vehicles** – The original Department authorized device deployment and projected cost was 500 locations and $55M, respectively. At term completion, 455 locations have been commissioned and $44.8M has been spent. At the end of calendar year 2021, the Company is underrunning by 45 locations and on target for cost projections, respectively. The underrun in unit deployment was driven by challenges related to the COVID-19 pandemic, supply chain, and slow initial uptake due to the nascency of EV market. The

Company plans to spend the remainder of the originally approved $55M in the first half of 2022, installing EV infrastructure at a total of 500 customer sites. Upon final completion of all work, including 2021 GMP investment carry-over work to be completed in 2022, the device deployment will be 500 locations and final costs will be at, or less than, $55M.

9. Energy Storage

- **Martha's Vineyard** – The original Department authorized projected cost was $15M. Based on the third-phase feasibility analysis, the Company determined that it was prudent to cancel the project due to increased project costs and updated information regarding the future load forecast for Martha's Vineyard. The Company notified the Department and stakeholders of this determination on May 17, 2021 in its 2020 GMP Annual Report (D.P.U. 21-30). The Company has provided more information regarding the notification in Section III F.

- **Provincetown** – The original Department authorized projected cost was $40M. At term completion, including 2021 GMP investment carry-over work to be completed in 2022, the final costs will be $50M. At the end of calendar year 2021, the Company is underrunning by $6.0M. This was a result of delay in commissioning the battery energy storage system in 2021.

E. Carryover Work into 2022

In order to operate efficiently and cost effectively, the Company develops capital budgets and work plans for the upcoming calendar year by starting the process in late summer of the current year. Prior to the 2018-2021 GMP, this process was typically only undertaken for business-as-usual capital projects, but now the process encompasses the incremental work to be undertaken under the GMP. This planning process allows for the development of cashflow, resource requirements, and ensures that projects are ready to execute on time. To maximize the yearly throughput, this means that to start in Q1 of the upcoming year, engineering and design must be completed prior to the year starting.

The Company has been able to incorporate the year-to-year incremental workload of the GMP program due to the understanding of the commitments and spending caps that were authorized by the Department. For GMP work plan year 2021, the Company positioned itself to be as prepared as possible to start engineering and design work once Department approval was received while conservatively expending funds, in the event that the continuing GMP investments were disapproved. Once approval was received per the Department's February 4, 2021 order in D.P.U. 20-74, the Company worked to reconfigure the budget and resource plans to support the 2021 GMP work. Unfortunately, due to the combination of the changes to the execution of the work plan, and several equipment delay issues, there are portions of the 2021

GMP that will carry over into 2022. The Company has built this carry over into its 2022 work plans. Figure 7 is a summary of the work that will be carried over into 2022 and is meant to include a comprehensive and quantified view of actual work deployment and costs in addition to the quantified carry over. All of the 2021 GMP investment carry over work had been initiated in 2021, represents investments that will continue to contribute to the Department's grid modernization objectives and will allow for a discrete conclusion to the 2018-2021 GMP work plan, without causing disruption or confusion to future GMP and/or base capital work plans.

Figure 7 Carryover Work into 2022

		Units (# of Units)			**Spending ($)**		
Investment Category	**Preauthorized Device Type**	**2018-2021 Actual**	**Carryover to 2022**	**Total 2018-2021 Actual and 2022 Carryover**	**Carryover to 2022**	**2018-2021 Actual**	**Total 2018-2021 Actual and 2022 Carryover**
Monitoring & Control (SCADA)	Microprocessor Relay	202	42	**244**	7,000,000	34,359,319	**41,359,319**
	4kV Circuit Breaker SCADA	54	14	**68**	1,700,000	18,259,341	**19,959,341**
	Recloser SCADA	59	0	**59**	-	3,385,470	**3,385,470**
	Padmount Switch SCADA	59	0	**59**	-	1,006,763	**1,006,763**
	Network Protector SCADA	91	0	**91**	-	1,433,958	**1,433,958**
	Power Quality Monitors	39	0	**39**	-	710,985	**710,985**
Distribution Automation	OH DA w/o Ties	334	9	**343**	450,000	24,709,155	**25,159,155**
	OH DA w/Ties	53	0	**53**	-	3,255,816	**3,255,816**
	4kV Oil Switch Replacement	172	0	**172**	-	30,194,757	**30,194,757**
	4kV AR Loop	18	0	**18**	-	2,296,669	**2,296,669**
Volt-Var Optimization	VVO - Regulators	97	3	**100**	225,000	3,986,740	**4,211,740**
	VVO - Capacitor Banks	74	25	**99**	700,000	3,571,796	**4,271,796**
	VVO - LTC Controls	8	0	**8**	-	1,452,402	**1,452,402**
	VVO - Line Sensors	205	20	**225**	130,000	1,432,698	**1,562,698**
	VVO - IT Work	N/A	N/A	**N/A**	-	2,677,280	**2,677,280**
	Microcapacitors	154	145	**299**	850,000	1,115,116	**1,965,116**
	Grid Monitoring Line Sensors	262	149	**411**	500,000	592,053	**1,092,053**
Advanced Distribution Management System (ADMS)	Advanced Load Flow	N/A	N/A	**N/A**	-	8,962,796	**8,962,796**
	GIS Survey (Expense)	N/A	N/A	**N/A**	-	-	**-**
	Dist. Management System	N/A	N/A	**N/A**	6,400,000	1,596,259	**7,996,259**
	Forecasting Tool	N/A	N/A	**N/A**	3,700,000	1,843,343	**5,543,343**
	Synergi Upgrades	N/A	N/A	**N/A**	-	942,445	**942,445**
	PI Asset Framework	N/A	N/A	**N/A**	300,000	1,076,564	**1,376,564**
Communications	Numbers of Nodes	10	6	**16**	2,500,000	2,406,701	**4,906,701**
	Miles of Fiber	2	2	**4**	500,000	1,146,668	**1,646,668**
Electric Vehicles	Electric Vehicles	0	45	**45**	6,200,000	44,757,255	**50,957,255**
Energy Storage	Martha's Vineyard	N/A	N/A	**N/A**	-	-	**-**
	Provincetown	N/A	N/A	**N/A**	9,800,000	40,060,593	**49,860,593**
	Total Capital Spending	1,893	460	**2,353**	40,955,000	237,232,943	**278,187,943**
	Preliminary O&M*				665,000	16,558,338	**17,223,338**
	Preliminary Total Spending				41,620,000	253,791,280	**295,411,280**

*2021 O&M spending will be finalized at the time of the Company's Grid Modernization Factor ("GMF") filing due to be filed by May 15th, 2022

II. Program Implementation

A. Organizational Changes to Support Program Implementation

1. Overview and Staffing Strategy Implemented

To ensure the successful and efficient implementation of the GMP, beginning in 2018, the Company layered the GMP into its existing business practices and leveraged the existing capabilities, processes, procedures, departments, and personnel within the Eversource system. Administratively, the portfolio of GMP programs is managed by a group of three dedicated positions, the Grid Modernization Portfolio Manager, Program Analyst and Financial Analyst. These three employees were hired externally after the date of the issuance of the Department's decision in D.P.U. 15-122, or May 10, 2018, approving the Company's GMP. These personnel were charged with developing and constructing the execution approach as well as overseeing all tracking, reporting, closing, and dispositioning activities for each of the GMP programs. Figure 8 below shows the total incremental labor for program implementation reported in labor dollars and FTE equivalents

Figure 8: Incremental Labor in Labor Dollars and FTE Equivalents

Incremental Labor Charged to O&M				
Charge Types	**2018 Actual**	**2019 Actual**	**2020 Actual**	**2021 Prelim**
Internal O&M - labor-related (a)	$ 104,708	$ 402,346	$ 348,523	$ 319,062
Average FTEs (b)	0.83	3.00	2.58	2.58

(a) - Labor for 2018 reflects 4 months, September through December.
(b) Average FTEs reflect 3 or less each year due to timing of when employees were hired and/or charging the program.

Given the scope and breadth of the GMP, the Company chose to integrate GMP work into Eversource's existing capital controls and processes in an effort to increase efficiency and best utilize specialized technical experts. The Company cannot support GMP work without using the internal functions necessary to complete capital work. Therefore, the Company layered the GMP into its existing business practices and is using its capabilities, processes, procedures, departments, and personnel within the Eversource system to plan, design, execute and complete GMP work. The Eversource GMP management team coordinates and facilitates oversight and engagement with multiple Eversource departments to implement the GMP, such as Procurement, Planning, Operations, and Information Technology ("IT"). This provides inter-departmental visibility into the various GMP program types and enables more effective and efficient planning of work and deployment of resources. There is a significant cross-functional work effort underway within the Company to support GMP execution, with over 1,000 internal Eversource employees directly involved in planning, executing, and monitoring GMP investments in addition to their routine job responsibilities, enabling the Company to ensure that the projects are optimally designed and executed with strong cost control measures in place.

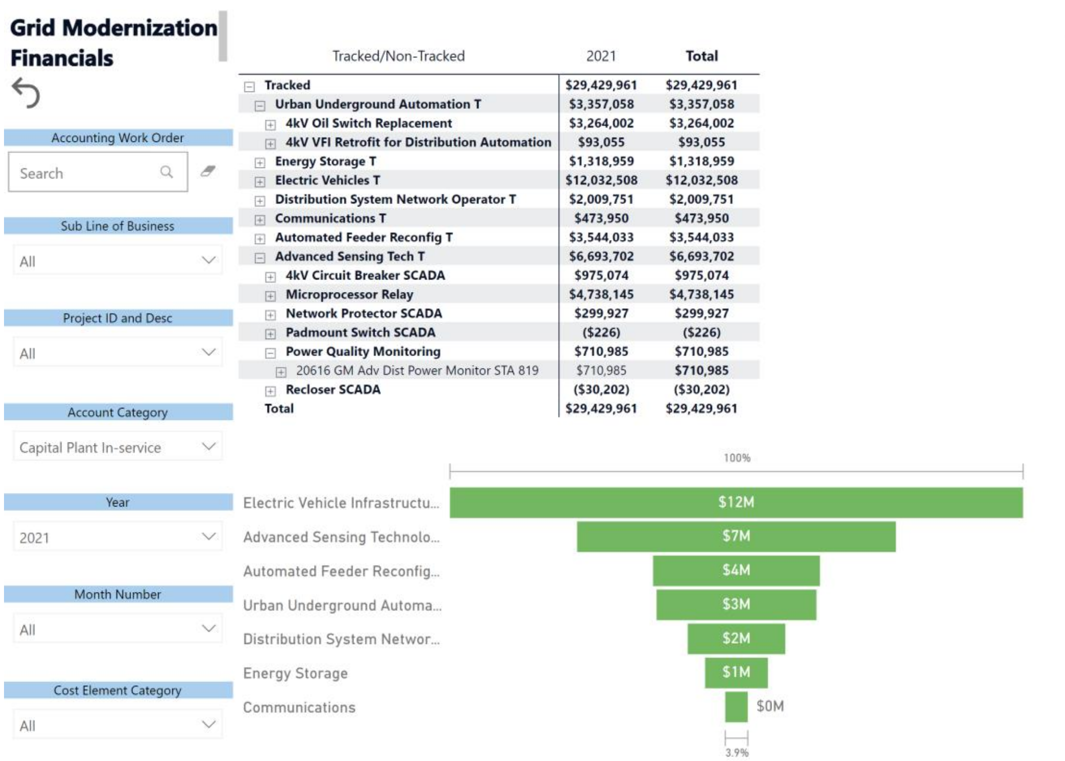
Consistent with the Department's decision in D.P.U. 15-122, none of the operations and maintenance ("O&M") expense associated with the GMP work performed by over 1,000 Eversource employees involved in planning, designing, and executing GMP portfolio work is included for recovery through the GMF. Consequently, the Company's customers are benefitting from the significant, system-related expertise that these employees bring to the implementation of the GMP. The Company is committed to implementing an innovative GMP in a measured and cost-efficient manner that benefits customers and continues to advance the Department's grid modernization goals, as well as the Commonwealth's critical energy and environmental policies. The use of these employees is critical to that outcome, although the O&M cost associated with their involvement is not recoverable through the GMF.

Administratively, to support the integration, the team developed a process framework to evaluate, analyze, align, and manage cross-functional responsibilities. Over the course of the four-year implementation period, the Company continued to make improvements to its tracking and reporting processes. The Company took the following steps to successfully implement and manage the GMP through 2021.

- **Evaluate/Inventory:** The team monitored progress towards the end-state goals of the GMP program and engaged the internal and external stakeholders required to influence program completion and success. Data collection and maintenance was a critical component of program management and involved mapping data from multiple systems including multiple work management systems (STORMs, Passport, and Maximo); the Company's financial reporting system (PowerPlan); the Geographical Information System ("GIS"); the Outage Management System ("OMS")**;** the Company's scheduling system (Primavera P6); and various other data sources. This data was aggregated into a centrally housed database ("GMP Portfolio Tracker") to enable report generation and analysis that was used over the course of the GMP to track investments and the Company's overall progress under the GMP.

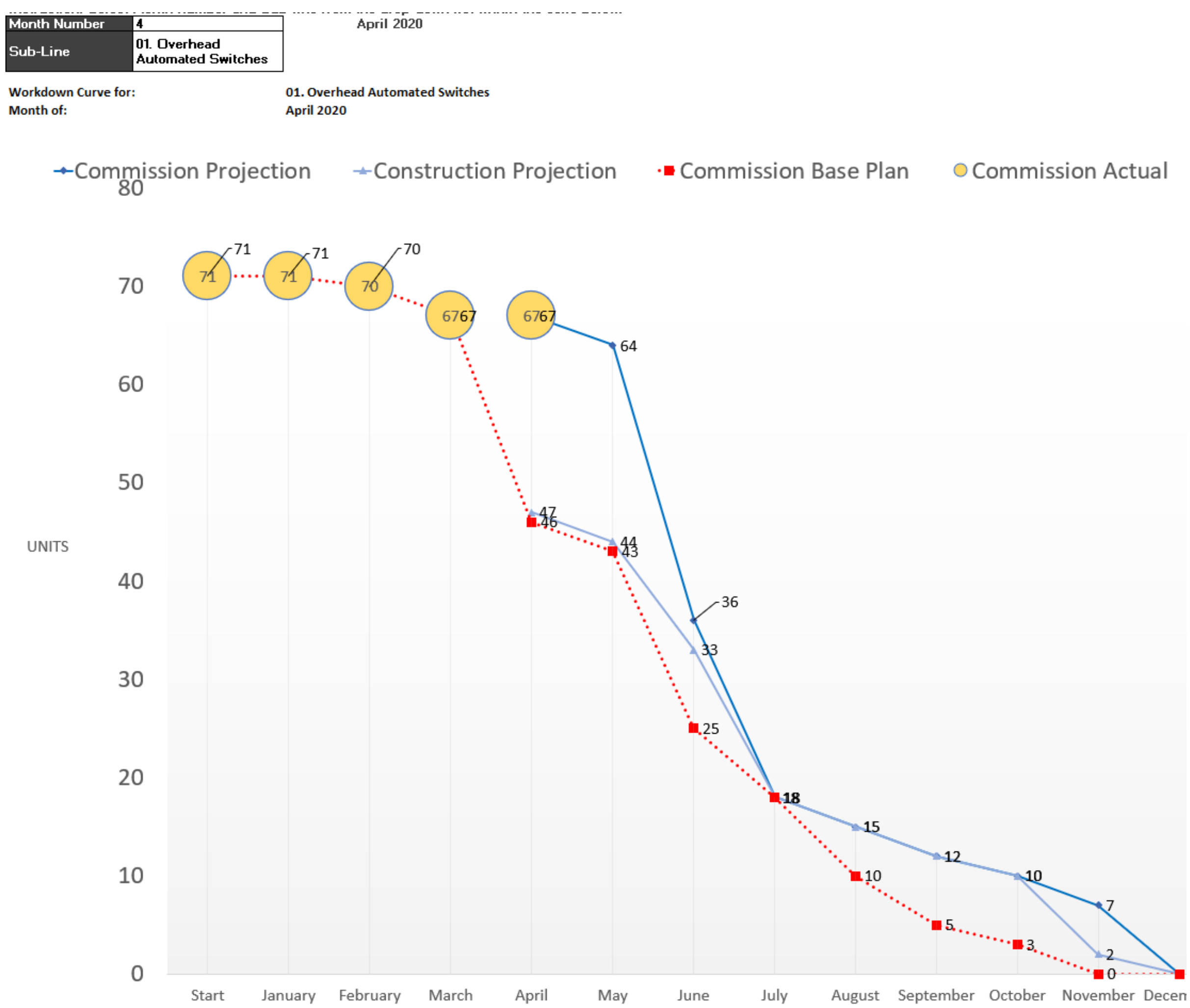
- **Analyze**: The GMP analyst further refined the data housed in the GMP Portfolio Tracker allowing for internal monitoring and reporting for quality assurance/quality control ("QA/QC") checks. This step was critical to successful GMP execution as it allowed for visibility into the GMP implementation, which enabled the Company to identify potential issues as early as possible during a given investment and develop and apply a resolution before the issue impacted the program. The Company also implemented granular tracking of the various elements of individual work orders in 2019 and added a more robust set of data to the recurring data downloads from the various Company systems. During 2020, tracking was further enhanced with the implementation of an automated dashboard that enables quick analysis of spend activity from the line of business level down to the specific work order, cost element, and account level. Because the GMP cost tracking process using Planning Analytics only allows for analysis at the project level, this new tool allowed for greater efficiency in reviewing the GMP financials. Prior to implementing the dashboard, the team did analyze this level of detail, however, it was previously a more manual effort that was time consuming. A screenshot of the financial tracking tool is provided below.

Figure 9: Grid Modernization Financials Tracking Tool



Align: The GMP represents incremental work that was overlaid onto and integrated with Eversource's existing controls and processes. Therefore, the project management team coordinated and facilitated a blended oversight and engagement of the various departments responsible for the execution of the GMP, such as Procurement, Planning, Operations, IT, and various administrative functions. This provides inter-departmental visibility into the various GMP program types and enables more effective and efficient planning of work and deployment of resources. In 2019, the Company added several enhanced reporting elements, including: 1) the addition of "Workdown Curves" that graphically communicate how the plan has been executed to date, and the remaining planned trajectory through the year end; and 2) monthly financial review meetings with key team members to facilitate immediate and decisive review allowing for greater understanding and frequent communication of the portfolio financials ensuring alignment across the Company's organization. A visual of the "Workdown Curves" for Overhead Distribution Automation has been provided below. In 2020, the team, shown in Figure 10, below, continued to develop more enhanced reporting elements to assist in the monitoring of and communication regarding the portfolio. For example, the creation of the automated dashboard mentioned above streamlined what was previously a very data intensive and time-consuming process. The team also made enhancements and refinements to processes based on information requests received from the Department and time spent working with Guidehouse on the measurement and verification ("M&V") process.

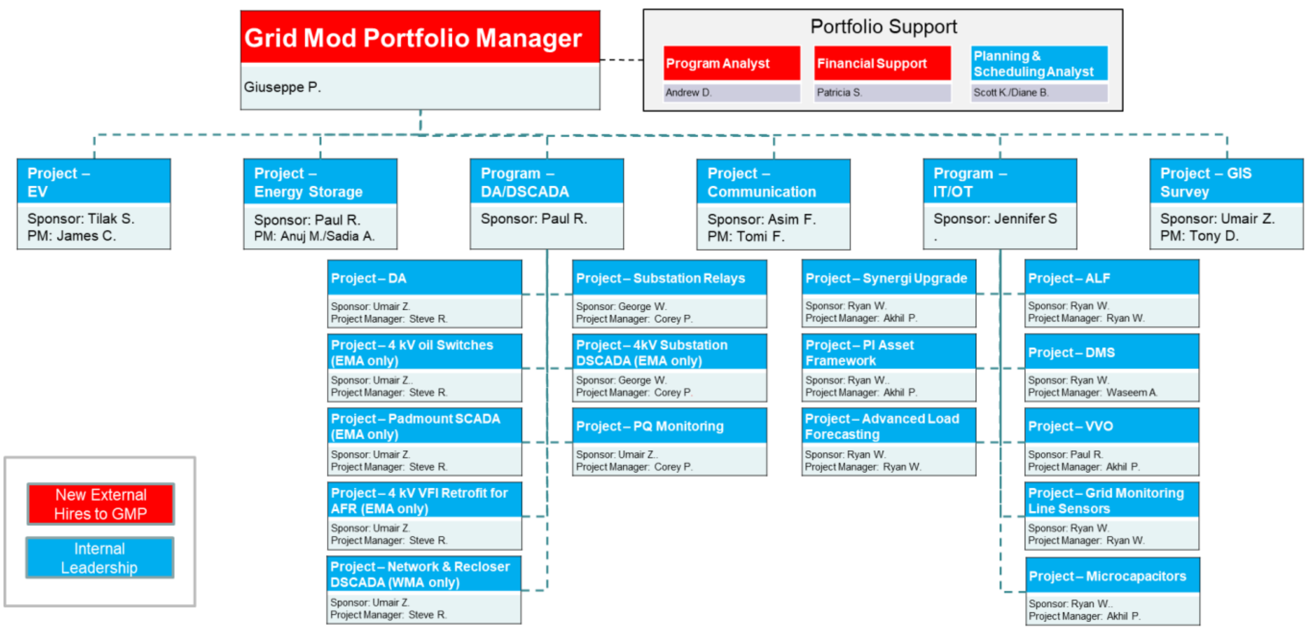
Figure 10: Workdown Curves Example for Overhead Distribution Automation from April 2020



- **Manage:** Using cross-functional GMP project managers, recurring status and coordination meetings, and recurring reporting, the core GMP project management team utilizes an execution platform to oversee and guide the implementation of the GMP program to ensure Eversource deploys the GMP investments in an efficient and effective manner designed to advance the achievement of the Department's identified grid modernization objectives. The team continued to monitor the various programs through earlier implemented methods, as discussed in prior year Grid Modernization Annual Reports. Being the fourth year of the program, 2021 did not see any significant changes to processes but instead retained a focus on accurate and real-time tracking.

These steps represent critical foundational steps that were developed and deployed to ensure that all GMP investments were undertaken in a deliberate and efficient manner. This framework was utilized in the execution of the 2018-2021 GMP and will be used for future GMPs.

Figure 11: Grid Modernization Organization



Operationally, the GMP is being implemented by a combination of internal and contracted operational personnel, such as line workers, electricians, technicians, IT developers, and commissioning agents. Eversource uses a matrix organizational structure, as can be seen in Figure 12 below, with many support functions cutting horizontally across the various operational resources. This structure promotes consistency across the enterprise and the ability to scale the organization to incorporate significant initiatives, such as the GMP.

Figure 12: Eversource Organizational Structure

Engineering:	Grid Modernization
	Distribution Engineering
	System Planning
	Substation Engineering
	Business and Quality Assurance
Operations:	Electric Field Operations
	Integrated Planning and Scheduling
	Electric System Operations
	Substation Operations
Safety:	Safety
Transmission & Major Projects:	Project Controls and Engineering
	Major Projects
	Siting and Permitting
	Project Controls and Engineering
Finance and Regulatory:	Controller and Accounting
	Financial Planning and Analysis
	Distribution Rates
	Corporate Finance and Cash Management
	Supply Chain Management
Corporate Relations & Sustainability:	Sustainability and Environmental Affairs
	Government Affairs
	Community Relations
	Regulatory Affairs
Customer Experience and Energy Strategy:	Electric Service Support and Distributive Generation
	Energy Strategy
	Energy Efficiency
	Strategic and National Accounts
General Counsel and Compliance:	General Counsel
	Compliance
Human Resources & Information Technology:	Employee and Labor Relations
	Enterprise Business Solutions
	Cyber Security
	Real-Time Business Solutions
	IT PMO

10. Lessons Learned/Challenges and Successes

- **Leverage proven, established processes to the extent possible.** The Company's ability to execute its 2018-2021 GMP plan was largely attributable to its ability to leverage existing processes and organizational capabilities. These efforts commenced in 2018 and continued through 2021. Using its existing project approval processes, the Company ensured consistency with its overall policies for capital budget spending authorization. In 2021, the Company continued to leverage its existing work management systems and processes to: create dedicated work orders for grid modernization projects; order standardized materials based on the Company's established competitive procurement policies; support planning and scheduling of work; and enable robust and accurate tracking of GMP investments. With respect to planning and scheduling, the Company created an integrated schedule for both GMP and base capital projects to ensure maximum execution efficiency and completion of the Company's full scope of work. As discussed elsewhere in this Term Report, the Company's GMP cost tracking and review processes ensured that costs associated with GMP investments were not intermingled with base capital projects and vice versa.

- **Dedicate effort to maximize cost-effectiveness of implementation.** Many of the decisions made early in the GMP implementation and throughout the course of the GMP term drove cost-effectiveness in achieving the individual project and larger program objectives. Program planning and program management efforts from early in the term provided foundational support to commence work in 2018 and continue work as seamlessly as possible through 2021. Assembling the right program management and governance team and keeping that team engaged throughout the plan duration drove efficiency and consistency, both of which increased cost-effectiveness. As mentioned in Section II.A.1, over 1,000 employees contributed to executing the GMP. Significant effort was dedicated to setting up and maintaining clear communication channels and communicating priorities across the organization. Emphasis on setting up maintaining the appropriate communication channels and cadence allowed employees to learn as they progressed, make course corrections as needed, and stay focused on completing the work within cost and scheduling constraints.

- **Establish a dedicated team for portfolio management and financial tracking.** The Company recognizes the critical importance of transparency and visibility in implementing its GMP portfolio. Ensuring accurate, timely tracking and reporting is a principal component required to ensure actions are taken to manage scope, schedule, and budget. Focus on tracking and reporting also supports robust performance reporting and active engagement in the M&V process.

- **Engage senior operations leadership to provide implementation guidance and support.** The Company's senior Operations and Energy Efficiency leadership have demonstrated a strong commitment to supporting implementation of GMP objectives. Leaders recognize the direct customer benefit and importance in enabling the continued transition to the grid of the future. Periodic meetings to review progress throughout the GMP, and leadership feedback on that progress continued to provide critical guidance on the implementation of the 2021 GMP. Portfolio governance by senior leadership ensured key decisions were well vetted with strong organizational alignment.

- **Develop an effective approach to implementation of new grid modernization technologies and capabilities.** Many of the programs included in the Company's GMP support deployment of existing monitoring and control, communication, and automation technologies. These types of programs are relatively amenable to leveraging existing processes and capabilities. Investments in Volt-Var Optimization ("VVO") and Advanced Distribution Management System ("ADMS") investment categories required the re-alignment of organizational structures and workforce augmentation. Additional work was also required relative to competitive procurement of new technologies. The Company leveraged its existing competitive procurement processes for the 2018-2021 GMP. Through this process, the Company was able to competitively procure the resources needed to construct and implement the Advanced Load Flow ("ALF"), Advanced Forecasting, VVO, and GIS Verification projects.

B. Cost and Performance Tracking Measures

1. GMP Accounting Process

The Company developed an accounting framework to ensure that GMP costs were isolated from all other O&M and capital project costs and were incremental to existing and business as usual investments. The GMP accounting framework started with the creation of new cost control centers for both Eastern Massachusetts and Western Massachusetts. Although the GMP was designed and implemented across the Company's service territory, the Company is still required, consistent with the Department's directives, to maintain separate financial records for NSTAR Electric and the former WMECO. D.P.U. 17-05, at 44-45. Next, the Company created separate lines of business for each investment type to track GMP projects and work orders separately from any base capital work. The separate lines of business are listed below:

- Electric Vehicle – 12165
- Energy Storage – 12160
- Advanced Sensing Technology – 12190
- Automated Feeder Reconfiguration – 12170
- Urban Underground System Automation – 12175
- Communications – 12180
- Distribution System Network Operator – 12185
- Grid Mod Admin and Regulatory - 12195

As the Company established its GMP implementation processes, three positions dedicated solely to the GMP program management and financial management were created and filled as shown in red in Figure 11 above. In D.P.U. 15-122, the Department limited eligible O&M labor expense to new positions created after the May 10, 2018 issuance of the order, unless the Company can demonstrate that the associated costs are attributed solely to grid modernization activities and are not otherwise recovered through rates. D.P.U. 15-122, at 222.

In D.P.U. 15-122, the Department directed the Company, as well as the other electric Distribution Companies ("EDCs") to: (1) propose a rigorous protocol to demonstrate that grid modernization expenses are incremental to the costs already recovered through base distribution rates; and (2) limit eligible O&M labor expense to new positions created after May 10, 2018. Id. The Company filed its proposed GMF tariffs on August 14, 2018 and proposed to use a full-time equivalents ("FTEs") test to establish whether internally transferred employees are incremental to the representative level of O&M expenses otherwise recovered in base distribution rates. The FTEs test ensures that there is no double recovery of labor costs between base distribution rates and the GMF put in place to recover the incremental costs associated with the Company's GMP investments.

The FTEs test is also wholly consistent with the Company's Performance Based Ratemaking ("PBR") Plan, both the PBR Plan approved in D.P.U. 17-05 and the proposed PBR Plan currently pending before the Department in D.P.U. 22-22. The fundamental purpose of a PBR environment is to promote the achievement of cost efficiency across the Company. Therefore, if the Department were to deny recovery of employee-related labor costs associated with the GMP based on a conclusion that the Company had been successful in optimizing its overall operations, the Department would be directly undermining the incentives that are established within the Company's PBR Plan. This would create a strong incentive to hire employees for the GMP only as external hires so that there is no possibility of losing efficiencies gained through hard work in optimizing the overall organization under the terms of the PBR Plan. This is an outcome that the Department should avoid because incremental programs such as the Company's GMP will be most cost efficient where qualified, experienced employees are hired to work on those programs, regardless of whether those employees are internal or external hires.

The Department held a technical conference to discuss the FTEs test that was submitted jointly by the Company and the other EDCs on December 20, 2018 and requested initial and reply comments on the proposed FTEs test by January 14, 2019 and January 25, 2019, respectively. Use of the proposed FTEs test is currently pending before the Department.

The Company created a mechanism for properly tracking all GMP labor charges. Originally a specific work order, GMPLBR21, was established to track these labor charges, but a new specific work order, GMPLBR00, was created to track all new external hires in which positions were created after the May 10, 2018 order and would not otherwise have been created but for the GMP, and therefore not included in base distribution rates. The change in work orders was completed so that costs associated with the external hires would be completely segregated and independent of costs associated with the pre-authorized GMP investments. All charges from the old work order were migrated to the new work order to retain all historic entries. Eversource internal labor direct charges their time to the relevant GMP work orders whenever possible and appropriate. In the event that these individuals cannot direct charge their time, their time is charged to Engineering & Supervision ("E&S") to be spread across all work orders consistent with Eversource accounting practice for all capital work. For existing employees, i.e., those individuals employed prior to March 15, 2018, all their labor expense and productive and non-productive time will remain as an expense in the employee's home cost center and is not recoverable under the current GMF. All outside services procured to design/implement/construct grid modernization capital units of property charge the GMP capital work orders and those costs are recoverable through the GMF.

11. GMP Cost Tracking Process

Total O&M and Capital Spend

The Company created a cost tracking process to track total spending for the entire GMP portfolio. This process was designed to be an accurate and repeatable process requiring minimal manual effort to ensure data consistency and that the spending was incremental. A customized view was created in Eversource's budgeting and financial application, Planning Analytics, that contains only GMP projects and lines of business. The view contains monthly actuals, budget, variance, and projection information that are automatically populated in Planning Analytics.

- Actuals – numbers feed into Planning Analytics directly from Eversource's other financial reporting system, PowerPlan.
- Budget – numbers are input into Planning Analytics at the end of each calendar/budgeting year for the following calendar/budgeting year. Budget numbers are locked down so that there cannot be any changes to the budget throughout the year.
- Variance – automatically calculated in Planning Analytics (Actuals-Budget).
- Projection – numbers are input into Planning Analytics monthly, based on historical performance and Actuals from the prior month.

As actuals accrue for each project, the projections are manually entered into Planning Analytics. The actuals, budget, variance, and projections populate in both a month to date and year to date view, and the data from the Planning Analytics view is extracted directly into Excel. On or around Business Day 4 of each month's accounting close process, the Grid Modernization Financial Analyst extracts the Planning Analytics data to perform a year-to-date and month-to-date variance analysis of the GMP portfolio and reports results to various groups internally. Analysis of Planning Analytics Actuals is also performed to further ensure that the Planning Analytics data is the same as the PowerPlan data.

Total Plant in Service

The Company has created a cost tracking process to track total plant in service dollars for the entire GMP portfolio. Total dollars placed in service cannot be tracked in the same manner as total capital spending because Planning Analytics does not contain the necessary FERC account information used to classify a work order/project as being in service. This information is extracted from PowerPlan, Eversource's financial reporting system. To populate this information, the Grid Modernization team established a query in PowerPlan to capture all costs distinctly associated with the GMP. The query contains detailed information needed to accurately and comprehensively track GMP costs, such as FERC Account, Accounting Work Order, Entity, Funding Project, Line of Business, etc. FERC Accounts 106010 and 101010 denote that an Accounting Work Order is in service. Similar to the total capital spending Planning Analytics process, the PowerPlan extract is performed by the Grid Modernization Financial Analyst on or around Business Day 4 of each month's accounting close process.

Controls and Ensuring Data Accuracy

The Company created various informal and formal tracking mechanisms to report on portfolio performance and ensure the accuracy of the data. In addition to the established accounting process described above, the Company scrutinizes and assesses the reported data. A mechanism was created to track GMP portfolio operational performance and analyze GMP work order activity. The reporting combines both financial and operational metrics of the GMP portfolio. Operational work order details are formally tracked using this reporting. Work order detail, including but not limited to, work order description, service center, costs and work order status are pulled into the reports from various Eversource systems. The Grid Modernization Program Analyst refreshes the data weekly. Eversource's work management system is queried weekly to pull GMP work orders that have been created. The population of work orders is cross-checked to the Company's financial reporting tool, PowerPlan. Data is organized by project and by the GMP-specific lines of business discussed above in the GMP Accounting Process section. Any identified inconsistencies are addressed and corrected in a timely manner. For example, if it is determined that a work order was inadvertently written to the wrong GMP project and/or line of business, the analyst would work with Engineering to cancel and rewrite the work order to the correct GMP project and line of business.

As a further review of the data, weekly meetings are held with diverse groups of Eversource personnel. The summarized GMP data, as well as detailed data from the tracking mechanism, is shared and analyzed during this meeting. In addition, the Grid Modernization Portfolio Manager shares additional information related to the program, such as program risks, issues, and progress towards internally established targets. The Grid Modernization Project Managers also report on progress made for their respective areas of responsibility. The weekly meetings provide a recurring opportunity and platform to discuss any issues related to or potentially impacting the GMP.

Informal processes also exist outside of the formal tracking reports and weekly meetings. Integrated Planning & Scheduling, Engineering, Procurement, Corporate Performance Management, and other functional groups across Eversource are in constant communication regarding all aspects of Company business, including the implementation of the GMP. Representatives of these various departments work cross functionally and collaboratively to meet GMP portfolio performance expectations. Stakeholders within these various departments also maintain their own tracking mechanisms, which are periodically cross checked against the formal GMP source document maintained by the Grid Modernization Program Analyst.

Grid Modernization Unit Tracking Process

GMP-qualified units are manually tracked by the Grid Modernization Program Analyst in the GMP portfolio tracking reports. As discussed above, all GMP work orders are reviewed and analyzed on a weekly basis, with any inconsistencies or other issues addressed proactively in a timely manner. Based on the attributes assigned to a GMP work order and depending on the outcome of the discussions and collaborations with the GMP Project Manager and/or Engineering, a GMP-qualified unit(s) is assigned to the appropriate GMP work order.

As described above, Eversource has developed a robust and detailed set of multi-disciplinary processes and procedures to track the costs associated with GMP projects to ensure that the Department's directives from D.P.U. 15-122 are comprehensively addressed. The Company's procedures allow for detailed analysis to support GMP investments and, eventually, cost recovery. Over the course of the 2018-2021 (and future) GMPs, the Company will continuously assess its tracking and reporting processes and, as appropriate, modify those processes and adopt best practices.

Project Approval Process

Consistent with the Company's Capital Authorization Policy and procedures, all GMP projects that were placed in service in 2021 have received the requisite spending authorization consistent with the requirements under the APS1 Project Authorization Policy. All GMP projects link to one of the specific GMP lines of business and all GMP work orders link to a specific GMP project, which rolls up to a GMP line of business. For GMP projects where the total costs are below $100,000, the authorization has been granted via the annual program blanket approval that occurs as part of the capital plan book review by the Company's Board of Directors. For GMP projects where the total cost exceeds $100,000, a specific project identification number is assigned, and a Project Approval Form ("PAF") is written and approved through the PowerPlan system following the delegation of authority process set out in the Capital Authorization Policy. For GMP projects requiring a PAF, if the project is expected to exceed the original authorized dollar amount, then a supplemental PAF is required when the direct costs of the project exceed or are expected to exceed the original authorized amount by the following levels:

- For projects <= $250K - An increase in direct costs >= $25K or;
- For projects >$250K - An increase in direct costs >10%.

(a) Ease of integration of Program cost tracking measures with existing practices, efficiency of separate tracking, and lessons learned

Setting up the Grid Mod Program with both a unique line of business structure and project reporting hierarchy has proven to be a valuable tool for cost tracking and reporting in GMF filings. It provides visibility of costs that makes it easier to review program spending at the line of business level, the project level, and individual work order level. This ensures that the work being completed is accurately reflected in the individual programs that are then filed with the Department for cost recovery through the GMF. From a financial reporting perspective, the Company can report on and review different program slices with a minimum level of effort. This allows for a better understanding of individual program costs.

As mentioned in earlier sections, the GMP leveraged proven and established processes, where possible. This made it a relevantly straightforward process to integrate program implementation and cost tracking measures with existing practices. Where existing processes were more limitedly available to leverage, a significant amount of time was invested in building out customized datasets and templates that supported robust reporting and analysis. This was mostly the case for infrastructure and performance metrics reporting, as well as active engagement in the M&V process as there was no existing processes to leverage.

12. GMF Tariff

On May 15, 2019, the Company filed with the Department a request for approval to recover approximately $1.5 million in grid modernization costs for calendar year 2018 through its proposed GMFs for effect July 1, 2019. On June 28, 2019, the Department issued its Order in

D.P.U. 19-23 (the "GMF Order") and disallowed the model GMF tariff and the proposed GMF tariffs filed by the Company in D.P.U. 15-122, as well as National Grid in D.P.U. 15-120 and Unitil in D.P.U. 15-121. NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 15-122-B/19-23, at 34 (2019). In its Order, the Department directed the Company to make a compliance filing with revised tariffs and a recalculated revenue requirement. Id. at 33.

Subsequently, on July 11, 2019, the Company, along with the other EDCs, filed a Joint Motion for Reconsideration requesting the Department review its determinations on three elements of the revenue requirement recoverable for annual grid-modernization investments in its GMF Order. These three components are: (1) the recovery of the current year revenue requirement on eligible grid-modernization investments made in the Investment Year and prior; (2) the recovery of property tax applicable to grid-modernization investments made in each year; and (3) the peremptory exclusion of all "overhead and burdens" associated with O&M expenses deemed eligible for recovery as incremental costs. The EDCs also requested that the Department incorporate provisions on the criteria for demonstrating incremental O&M expenses eligible for recovery and the treatment of grid-modernization investments as part of rate base in a base-rate proceeding, which were omitted from the Department's GMF Order.

On July 17, 2019, the Company participated in a conference call with the Department, resulting in a revised revenue requirement calculation. In accordance with the conversation and in compliance with the GMF Order, the Company filed a revised GMF tariff, M.D.P.U. No. 73A, and updated GMFs for effect September 1, 2019. On August 1, 2019, pursuant to D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 225-226, the Department directed the Company to supplement its filing with certain required documentation of its proposed incremental O&M labor expenses. NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 19-23, Hearing Officer Memorandum (August 1, 2019). The Company complied with this request and supplemented its filing on August 12, 2019 with the required documentation.

On August 28, 2019, the Department issued an Order approving the Company's revised tariff, M.D.P.U. No. 73A, and approved the proposed GMFs for effect September 1, 2019. NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 19-23-A, at 6-7 (2019).

As of the date of this filing, the Department has not issued an Order on the EDCs' July 11, 2019 Joint Motion for Reconsideration.

The Company respectfully requests that the Department take action on both the FTE test and the Joint Motion for Reconsideration. Given the importance of advancing the Department's grid modernization objectives, as well as making progress towards advancing the Commonwealth's energy and environmental goals, there is a clear need for predictability and transparency in relation to the recovery of grid mod investments that are critical to these objectives for the benefit of the Company's customers. This is particularly true as the Company prepares to implement its 2022-2025 GMP following the Department's review and approval of that plan.

Regarding the issues raised in relation to the GMF tariff in the Joint Motion for Reconsideration, the Department had laid out a deliberate path for the GMP cost-recovery mechanism, including a sequence and timing for cost recovery that allowed recovery of the "current calendar year revenue requirement" associated with GMP investments, once those investments are placed in service and are used and useful for customers. D.P.U. 15-122, at 225-227. Currently, there is a substantial regulatory lag of almost two years that is inconsistent with the Department's determinations in D.P.U. 15-122. There, the Department stated its intention to adopt a factor designed to: (1) remove financial barriers to a reasonable level of investment in grid modernization technologies, without *eliminating entirely the regulatory lag* that provides an important incentive for a company to spend efficiently; and (2) provide for recovery of costs through the GMF *after the expenses have been incurred* and the associated investments have been placed in service and are used and useful to customers, rather than relying on projected expenditures and revenue requirements. Id. at 224-225. Thus, the Department indicated an intent to provide for the recovery of investments made in one year in the subsequent year representing a lag of approximately one year and the EDCs' model tariff provisions were carefully designed to remain aligned with that reasonable intent. <u>See</u>, <u>id</u>. at 224. The Department gave no indication in its D.P.U. 15-122 order that it intended to ***eliminate*** recovery of the "current calendar year revenue requirement" in relation to GMP investments that are used and useful in prior GMP Investment Years. Further, the financial barriers associated with such an extended lag will be particularly significant in circumstances where an EDC, like the Company, is precluded from filing a base-rate case due to a committed stay-out period under a performance-based ratemaking plan.

As for the FTE test, the Companies have developed, presented, and thoroughly supported a test to determine incremental O&M expenses, as well as a test to determine whether recovery of O&M related overheads and burdens should be allowed. The Department's decision to: (1) preclude any recovery of O&M-related overheads and burdens, even where it is demonstrated that O&M labor is incremental; and (2) approve the GMF tariff without criteria for determining the eligibility of incremental O&M expenses for recovery is entirely inconsistent with the Department's findings and directives in D.P.U. 15-122. It is clear that FTEs are vital to the success of the GMP, as the Company has demonstrated that the personnel required to implement the GMP were hired after the date the Department issued its order in D.P.U. 15-122 and would not have been hired but for the establishment of the GMP and need for program managers to oversee the successful implementation of the GMP.

III. Term Implementation System Level Narrative by Investment Category

The following sections summarize the term implementation system level narrative by investment category. Further detail on overall portfolio implementation and deployment data is available in the Appendix 1 attachment.

A. Monitoring and Control

1. Performance on Implementation/Deployment

Refer to Figure 13 and Figure 14 below for the Company's 2018-2021 implementation unit and spending summaries for the Monitoring and Control GMP Investments.

Figure 13: 2018-2021 Monitoring and Control Implementation Unit Deployment Summary (# of Units)

Investment Category	Preauthorized Device Type	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2018-2021 Actual	2018-2021 Projection*	% Difference
Monitoring & Control (SCADA)	Microprocessor Relay	10	87	83	22	202	237	-15%
	4kV Circuit Breaker SCADA	0	16	38	0	54	67	-19%
	Recloser SCADA	15	19	25	0	59	59	0%
	Padmount Switch SCADA	3	41	15	0	59	59	0%
	Network Protector SCADA	0	0	83	8	91	104	-13%
	Power Quality Monitors	0	0	0	39	39	34	15%

Figure 14: 2018-2021 Monitoring and Control Implementation Capital Spending Summary ($)

Investment Category	Preauthorized Device Type	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2018-2021 Actual	2018-2021 Projection*	% Difference
Monitoring & Control (SCADA)	Microprocessor Relay	3,363,115	14,991,129	11,737,080	4,267,995	34,359,319	41,351,117	-17%
	4kV Circuit Breaker SCADA	83,747	4,085,366	11,763,300	2,326,928	18,259,341	19,932,413	-8%
	Recloser SCADA	963,353	888,665	1,533,849	(397)	3,385,470	3,385,867	0%
	Padmount Switch SCADA	105,723	615,476	285,790	(226)	1,006,763	1,006,989	0%
	Network Protector SCADA	-	871,602	559,572	2,784	1,433,958	2,148,174	-33%
	Power Quality Monitors	-	-	214,937	496,048	710,985	1,170,506	-39%

(a) Microprocessor Relays

The Company's original plan was to deploy relays on 213 feeders. This proposal was based on an estimate from the original filing. After approval of the 2018-2020 GMP, and as the Company executed the program, original assumptions associated with the specific substations and their respective circuits changed due to changes in conditions necessitating a change in substation priority and/or adjustments in order to efficiently plan resource utilization, which may have caused another substation to raise in priority. Through each step, the Company took specific and calculated decisions while administering the program in order to fulfill budget and resource constraints in addition to Department commitments. Additionally, due to the similar nature of the work, the 4kV Circuit Breaker SCADA program was executed with like personnel, processes, and resources as the Microprocessor Relay program. Through this similarity, the Company focused on the aggregate of these two programs, when making changes to unit counts, so as to meet the combined Department commitment.

The Company originally committed to deploying relays on 213 feeders as part of the 2018-2020 GMP and 33 feeders as part of the 2021 GMP deployment plan approved in D.P.U. 20-74 (246 feeders total). As discussed above, at the completion of 2021, the Company fully installed and commissioned relays on 202 feeders. The Company's intent was, and still is, to deploy relays on an additional 42 feeders in 2022. These 42 feeders were planned for 2021, but due to the historic knowledge for project timelines, the Company anticipated there would not be sufficient time to fully complete the installations. Therefore, for 2021 all engineering and design was completed for the remaining 42 feeders and the relays are resourced and planned into the 2022 GMP investment schedule.

As discussed in prior GMP Annual Reports, projects in this investment category were concurrently executed throughout the Company's entire Massachusetts region. Each year, significant effort was taken to reinforce the team, validate locations, and execute the plan to install the microprocessors simultaneously at multiple locations. To leverage experience, the Company utilized the same teams that were undertaking the 4kV Circuit Breaker SCADA program. Although the Company fell short of its 2018-2021 goal, this significant coordination and concerted effort represents the level of commitment at the Company to the GMP and demonstrates the Company's ability to leverage internal and external expertise to continue the successful implementation of the GMP.

The Company's original total capital costs were estimated at ~$27M for the 2018-2020 GMP and $9M for the 2021 GMP approved in D.P.U. 20-74. After program initiation and execution, the Company determined that the budgets developed for the original filing (D.P.U. 15-122) were inadequate. The actual costs were on average higher than expected and the cost information that was acquired during the 2018-2020 GMP allowed the Company to develop further refined budgets for the supplemental 2021 GMP. The actual total capital costs for the deployment of relays at 244 feeders is expected to be $41.4M. The following provides further details into the program costs.

- Originally, the Company expected that following the initial program startup costs and compressed duration contracted work that was experienced in 2018, actual future unit-costs would come further into alignment with budgeted unit costs. However, after continued operations throughout the GMP, which included a competitive procurement process, efficiencies in team cooperation, and better planning, the costs still deviated higher than the originally budgeted values. This is principally due to the use of specialty contracted resources and the overtime required to perform this incremental work internally.

- Because of the significant deployment, plan year 2019 was the defining year for the Company to fully appreciate the expected costs of deployment for this program. The Total Capital Spend of the unit-costs for this program were estimated to average higher than originally budgeted unit costs and it was the information gleaned from 2019 that enabled the Company to refine and reestablish a total program budget. Through execution of the entire GMP program, the Company looked for efficiencies in both cost and execution. For example, economies of scale in some locations were realized by grouping Microprocessor Relay projects to be completed in parallel with other (potentially non-GMP) projects within the same substation. The costs associated with any parallel work streams, both GMP and non-GMP-related, followed the Company's rigorous cost tracking protocol to ensure that only GMP-related work was charged to the relevant lines of business. Additionally, GMP project costs were reviewed in real-time, and adjustments/decisions were made where needed, at the project level, to analyze and reallocate funds across GMP programs as appropriate and without negatively affecting those programs.

- In analyzing the cost increases from budget to actual, the Company has identified several drivers of the increases:

    - Each substation addressed in the Microprocessor Relay program had some commonality, but also a certain uniqueness that required various levels of effort, and money, to address. It was the unique nature of the substations, coupled with the corresponding resource/skill set(s), that resulted in the variations in implementing Microprocessor Relays at the substations, including the unit costs.

    - Due to the incremental nature of the GMP work, it was often necessary to engage vendor resources to augment the Company's internal staff. Many of these resources have limited availability, such as Lead Commissioning Engineers ("LCEs") and Substation Test Engineers, both of which perform work for many aspects of the Company, in addition to the GMP. The Company's solicitations are typically distributed to approximately four technically qualified companies. Due to their significant experience, two of the four firms are highly sought after. These resource limitations in the market have led to increased negotiated rates over the last several years. This trend is expected to continue as more and more of the Company's, and the electric distribution sector in general, devices become more complex and interconnected.

    - Additionally, labor hours, particularly by contracted resources that cannot easily be redeployed, encountered an increase in actual costs relative to estimated costs due to COVID-19 restrictions and project delays experienced while Company personnel fulfilled their Emergency Response Plan ("ERP") duties during storm preparation and response.

- As an assumed result of the COVID-19 economic effects, many equipment vendors were challenged with providing equipment and materials in a timely manner. This was most evident in late 2020 and 2021.

(b) 4kV Circuit Breaker SCADA

The Company's original plan was to deploy relays on 41 feeders. This proposal was based on an estimate from the original filing, D.P.U. 15-122. After approval of the 2018-2020 GMP, and as the Company executed the program, original assumptions associated with the specific substations and their respective circuits changed, due in part to changes in conditions necessitating a change in substation priority, and/or refined planning resource utilization, which may have caused another substation to rise in priority. Through each step, the Company took specific and calculated decisions while administering the program in order to fulfill budget and resource constraints in addition to Department commitments. Additionally, due to the similar nature of the work, the Microprocessor Relay program was executed with like personnel, processes, and resources, as the 4kV Circuit Breaker SCADA program. Through this similarity, the Company focused on the aggregate of these two programs, when making changes to unit counts, so as to meet the combined Department-commitment.

The Company originally committed to deploying relays on 41 feeders as part of the 2018-2020 GMP and 14 feeders as part of the supplemental 2021 GMP (55 feeders total). As discussed above, at the completion of 2021, the Company fully installed and commissioned relays on 54 feeders (Figure 13, above). The Company's intent was, and still is, to deploy relays on an additional 13 feeders in 2022. These 13 feeders were planned for 2021, but due to the historic knowledge for project timelines, the Company did not have sufficient time to fully complete the installations following the February 4, 2021 issuance of the order in D.P.U. 20-74. Therefore, for 2021 all engineering and design was completed for the remaining 13 feeders and the relays are resourced and planned into the 2022 schedule.

The 4kV Circuit Breaker SCADA program experienced identical challenges to the Microprocessor Relay program. The Company was just shy of the original 2018-2021 GMP commitment, by one feeder, but is still committed to completing the remaining stretch goal of 13 feeders.

The Company's original total capital costs were estimated at ~$5MM for the 2018-2020 GMP and $4M for the supplemental 2021 GMP. After program initiation and execution, it was determined that the budgets associated with the original filing needed to be refined. The actual costs were on average higher than expected and the cost information that was acquired during the 2018-2020 GMP enabled the Company to develop more refined budgets for the supplemental 2021 plan. The actual total capital costs for the deployment of relays at 67 feeders is expected to be $20M.

Total capital spend for this program was anticipated to average higher than the original budgeted unit costs. The Company reviews project costs in real-time and makes adjustments/decision where needed at the project level and analyzes and reallocates funds across GMP programs as appropriate consistent with the Department's order in D.P.U. 15-122. In this case, unused funds from other GMP investment categories were utilized to account for higher budgeted costs. The increase in unit costs was principally due to the use of specialty contracted resources and the overtime required to perform this incremental work internally.

(c) Recloser SCADA:

The Company originally committed to deploying radio equipment only on 37 existing reclosers for $2.4M, in order to enable SCADA capabilities at these locations. However, as the program was executed, the team exhausted all locations that would allow for a radio-only solution. As discussed in the "Lessons Learned" section of the 2019 GMP Annual Report, the Company shifted this program from a radio-only installation to a 'replace, in-place' program. The 'replace, in-place' process included removing existing oil-filled recloser units and replacing them in their entirety. This was an efficient way to continue to deploy SCADA communications to existing field locations, with the added benefit of eliminating oil-filled equipment. The team is familiar with completing this type of work and was able to leverage existing processes to implement this incremental investment on the Company's system. Due to its efficient and effective processes and planning, the Company was able to exceed its commitment goal of 37 units by 22 units for a total deployment of 59 units.

The Company's original total capital costs were estimated at $2.4M. The actual total capital costs for the deployment of 59 units, inclusive of the revised "replace, in-place" process, were $3.4M. The Company deemed the additional unit deployment and cost to be an effective way to support the Department's grid modernization objectives with respect to these investments.

(d) Padmount Switch SCADA

The Company originally committed to deploying radio equipment on 62 existing Padmount switches for $0.8M, in order to enable SCADA capabilities at these locations. However, as the program was executed, the team exhausted all locations that would allow for a radio-only solution. The Company was able to deploy 59 units, which is three units short of the Department commitment.

By 2019 the Company had identified sufficient locations for Padmount switch upgrades during the earlier engineering stages. However, when full designs were completed, several prospective sites were removed from the execution list due to lack of upgrade compatibility. This was identified in 2019 GMP Annual Report as a potential risk in meeting the original Department commitment. This situation is similar to the condition experienced in the Recloser SCADA program. The Company analyzed implementing a "replace, in-place" strategy for the Padmount switch equipment but rejected this change due to a disproportionate installation cost.

The Company's original total capital costs were estimated at $0.8M. The actual total capital costs for the deployment of 59 units was $1M. The total capital spend for this program indicates that the average unit costs are slightly higher than budgeted. Based on the Company's analysis into the cost increases, it determined that much of the increase was associated with the time and effort to analyze and validate the chosen locations for these devices, as well as the additional work that was sometimes required to allow the existing device to operate with the installed communications package.

(e) Network Protector SCADA

The Company originally committed to deploying network protector relays on 83 existing network protectors for $5M. This program integrated the Digital Grid solution. The Company was able to successfully commission all of its 83-unit target of devices, including substation upgrades for the originally planned project in West Springfield, Massachusetts. Additionally, the Company added another substation, which included eight network relays, into the plan. This additional work was completed in Pittsfield, Massachusetts and was in addition to the original 2018-2020 GMP investment commitment. The team successfully installed all eight relays and accompanying substation equipment in 2020 but an unforeseen issue within the power line carrier infrastructure would not allow the field devices to communicate with high fidelity to the substation. The team pivoted quickly to develop a new solution to solve the problem and was able to fully commission the system in Q1, 2021.

As can be seen in Figure 13, above, this program has a variance of 13 units that have not been deployed. Again, the Company met its investment commitment in 2020 but had a stretch target of 21 units at two different substations built into the GMP. Unfortunately, the station with the remaining 13 units had an emergent repair, which required a substantive change to the substation. This condition prevented the team from commencing the Network Protector SCADA project at this location and, due to timing of the required repairs, it was impractical to complete the work as part of the GMP. Therefore, the Company does not intend to complete these 13 units indicated in Figure 13.

The Company's original total capital costs were estimated at $5M, in order to enable SCADA capabilities at these locations. The actual total capital costs for the deployment of 91 units, was $1.4M. At the time of the original GMP filing, the exact system configuration was not known. However, after final design and the efficiencies in work execution, there was significantly more budget to allocate. The Company employed the Digital Grid system at an additional network within the Western Massachusetts territory, as described above, and re-deployed the remaining portion of the budget to other GMP programs.

(f) Power Quality Monitoring

The Company added the Power Quality Monitoring program into the supplemental 2021 GMP. This program was designed to deploy a sub-cycle circuit monitoring system on 34 feeders within one substation for $1.2M. This system would allow the Company to be notified of system perturbances at levels that were not previously possible. It can be seen in Figure 13, above, that the Company deployed 39 monitoring devices, which is five more than the original GMP commitment. These additional monitors were deemed to be a prudent addition to the substation's bus system since they provided even more data regarding system operation.

The Company's total capital costs were estimated at $1.2M. The actual total capital costs for the deployment of 39 monitors was $0.7M. The cost variance is due to the Company's original assessment of deploying this brand-new technology. There were certain elements of work that were not required, and with no use of the allocated contingency, the overall cost was lower than expected. The Company expects to utilize this first deployment to inform all future power quality monitoring work.

13. Lessons Learned/Challenges and Successes

The Company utilized a programmatic framework when implementing the GMP. The importance of this framework and the Company's top-to-bottom commitment to the program cannot be overstated. It was this framework that allowed for real-time tracking and timely identification of real, or potential, deployment and/or financial challenges. Several of the following Lessons-Learned/Challenges and Successes are program-agnostic and apply to the GMP as a whole:

- The Company continued the process of communicating the GMP investments and status which enabled recurring and as needed, ad-hoc meetings, with all levels of the leadership, so that issues could be quickly raised, and resolution action plans enacted.

- The significant deployment efforts early in the GMP positioned the Company to better manage program-to-program variances or changes that occurred late into the term, while still meeting or exceeding GMP commitments in most preauthorized deployments.

- The unpredicted onset of the COVID-19 pandemic originally caused the Company's execution efforts to contract, while the impact assessment was being made. This had an immediate and downstream negative effect on project plans, some of which could not be overcome in 2020. However, after a relatively short delay, the Company took action and implemented definitive and conservative measures and protocols, that both protected Eversource employees and allowed work plans to recommence.

- The new Company policies and procedures used to manage the COVID-19 pandemic did have an impact on production, particularly in closed-in areas like substations, but the

Company's personnel quickly pivoted and integrated these new policies and procedures into their day-to-day work, again, to keep the programs moving forward.

- The downstream effects of the COVID-19 pandemic on the supply and logistics functions of the Company were felt in 2021 and further amplified into 2022.

2020 had an unprecedented number of weather-related emergency response events for the Company, both within Massachusetts and in the other Eversource Energy service territories, i.e., Connecticut and New Hampshire. Although the Company effectively manages emergency response events, the immediate re-deployment of personnel from project work, like the high-paced GMP program, caused delays that were often longer than the day-for-day absence of those employees. Delays were often exacerbated by missing/re-scheduling a planned outage. Delays added to cost pressures due to accelerating efforts to catch up, or the idling of project-specific contracted resources during Company personnel redeployment periods.

Due to the project management consistency that was retained among the various GMP programs, project managers, based on their earlier GMP experience, capitalized on enhancing efficiencies and worked to eliminate issues and challenges. Additionally, at the onset of many of the GMP programs, new vendor/contractor resources were sourced, which required an onboarding and acclimation timeframe before full efficiency could be achieved. The unbroken continuation of working with these same vendors in the later years of the 2018-2021 GMP allowed the GMP teams to better interact with various people/groups/departments and gain momentum in execution.

- Once contracted and scheduled, the onboarding of new external employees to an existing workforce will always provide challenges until both teams learn each other's cultures, habits and work styles, and become fully integrated. The timeframe for this integration can vary greatly. However, once the teams worked through these initial interactions and processes, production and efficiency continued to increase. The Company worked hard to limit any demobilization of a contracted resource once they had been onboarded to avoid the inherent slow-down of the integration process.

(a) Microprocessor Relays

Work completed within a substation typically requires significant coordination between Company departments. Due to the fast-paced nature of each of the substation projects, ensuring tight coordination still presented challenges throughout the program. Obtaining the right mix of internal and external resources also provided some challenges, mostly during the solicitation and onboarding process. As an example, the contracted resources required for this work are both highly specialized and limited within the marketplace. To compete for services and receive competitive pricing, it was important for the Company to solicit multiple projects to provide a definitive pipeline of work that could be completed in succession under a single mobilization as opposed to single projects spread out over the year with numerous mobilizations/demobilizations in between projects.

Substation work is often complex and comprehensive. It has been the Company's experience with previous, non-GMP substation projects that, during the execution of the initially scheduled project, it is possible to identify unforeseen conditions and/or additional conditions that are appropriate and prudent to repair/replace in concurrence with the original work scope. This approach is logical, common in the industry and cost-efficient. The Company is following this same operational approach for any substation work being constructed under the GMP, while ensuring that all costs associated with any work completed that is not due to or related to GMP investments are segregated from the GMP and accounted for separately. The Company has successfully balanced funding and the completion of any prudent ancillary substation work and maintained a strict segregation between GMP and non-GMP costs. After reviewing several completed project locations (substations), the team determined that these efficiencies resulted in a unit-cost savings of 30-40%, as compared to performing this work independently and on a stand-alone basis.

Since all GMP-related substation work is incremental to the Company's base capital business, and because much of the substation work requires the use of highly skilled or niche-skilled resources, securing external labor with the requisite skills and experience to assist with this aggressive program was challenging, though not insurmountable. The Company continued to work with the appropriate vendors, as far ahead of construction as possible, utilizing the 2018-2021 GMP set of projects to help secure these contracts, when/where needed.

Due to the fast pace of the program and external obstacles, such as the on-going COVID-19 pandemic, there were still many challenges with planning and execution of the interdependencies among internal departments and between contracted resources. However, lessons learned from the pre-planning process allowed the team to solicit external vendors further in advance while obtaining buy-in from internal departments. These improvements, which are difficult to quantify, allowed for more work to be completed in an efficient manner.

Leveraging the lessons-learned from early in the program, the Company utilized the 2018-2021 GMP project plan to secure external resources earlier in the process. This allowed the teams to secure highly skilled, niche resources in an efficient and effective manner. However, as discussed earlier in this Microprocessor Relay lessons learned section, when there were disruptions to the longer-term vendor plan, particularly due to emergency response, vendors may have had to demobilize and remobilize and/or incur standby costs until they could reengage with the projects.

The Company had originally intended to explore the possibility of utilizing third-party packager/kitting firms to assist with aggregating and coordinating materials (often from third-party vendors), so that the correct material was delivered when needed. Investments such as the Microprocessor Relay and 4kV Circuit Breaker programs do not require overly complex materials. However, there are many common parts and pieces that need to be coordinated to ensure they are on site at the correct times. Additionally, the volume of these projects is significant. Since the procurement process requires multiple Company departments to be involved in the specification, procurement ordering, delivery and receipt of material, the advantage of using a firm such as a third-party packager is the ability to free up these internal Company resources to focus on more pressing and complex issues as opposed to these fairly standard and recurring projects. After consideration, the Company deemed that it was not practical to implement this process as a mid-stream change to the GMP. The efforts of a third-party vendor to assist in pre-packaged materials are being explored for the 2022-2025 GMP.

As is typical with most construction projects, particularly renovation projects, pre-construction evaluations, which are referred to as "walk-downs," are critical to minimize unforeseen conditions and ensure that initial designs are adequate. After the completion of the first set of projects, the Company launched additional efforts to complete more comprehensive walk-downs. However, the ability to fully analyze existing conditions was not always possible due to energized components that may require an outage to inspect. Unforeseen conditions still occurred throughout the projects, and the Company has, and will continue to make more concerted efforts to observe and record existing conditions, prior to engineering and design efforts.

(b) 4kV Circuit Breaker SCADA

The 4kV circuit breaker SCADA work is very similar to the Microprocessor Relay program and has similar feedback on the lessons learned.

There is one lesson learned that was specific to the 4kV SCADA program due to its initial deployment in 2020. Due to the newness of this program, certain assumptions needed to be made at initial engineering and design phases. Some of these assumptions needed to be modified during the construction phase, partly due to unforeseen field conditions and partly due to refining the original scope of work to ensure conformance with the GMP.

As in other areas of the GMP execution, the project teams have continuously worked to refine the scope of work and execution methods, based on prior program experience.

(c) Recloser SCADA

This program has been instituted in the Company's Western Region ("WMA") where the Company identified significant opportunities to enhance SCADA sectionalizing capabilities, particularly on long feeders. Early in the program, the Company exhausted all locations that would allow for a simple communications package to be added to existing, older recloser locations. As an alternative, the Company pivoted to a "replace, in-place" process which fully replaced older, oil-filled recloser locations that did not have full SCADA capabilities with new SCADA-enabled vacuum reclosers. This program was very successful and due to the efficiency in the installation process, the Company deployed equipment to more locations than was originally anticipated in the 2018-2020 GMP.

Commissioning resourcing, due to their specialized skill set, was identified early as an area of opportunity. The Company placed emphasis on planning and monitoring of the Commissioning team and developed an aggressive but executable plan to complete the work. This plan was socialized well in advance, with relevant parties, so that the various Company departments were aware of the larger-than-normal influx of work. This helped with pre-programing devices in the area work centers, making sure devices were ready to go for physical installation, and allowed for better coordination of commissioning to avoid overly extended workloads. This effort allowed for a reasonable work curve, opposed to "bow waves" of work.

The long-range planning of resources, combined with the type of work, allowed for an increased quantity of deployment at an expanded scope, while retaining a reasonable cost.

(d) Padmount Switch SCADA

Early during this program's deployment, the Company had challenges with identifying the combination of the correct field device type locations that would allow for sufficient communications methods. This placed the program behind schedule. All possible locations were validated in early 2019 and the final number of locations was solidified.

Consistent with the discussion in the 2019 GMP Annual Report, the Company anticipated that its experience with Padmount Switch SCADA would be similar to its experience with the Recloser SCADA program, including the potential to exhaust the list of those locations where simply adding a communications package to an existing Padmount switch was feasible. This proved to be accurate in 2020 as the Company exhausted all such locations in its service territory. Given these location restraints, the Company was three units short of the original 2018-2020 GMP target. Because of the significantly increased costs associated with the equipment and installation of a 'replace, in-place' Padmount switch, the Company elected not modify this investment category and instead concluded the program, which ended up being three units short of the originally planned goal.

(e) Network Protector SCADA

The most significant lesson learned for this program was that the Company should have segregated the field work, which was presented to the Department on a unit-basis, from the substation work, which comprised the more significant work effort and is not attributable to a "unit." The completion of the substation work was required prior to any of the field relay devices being able to be commissioned into the new system.

The Company underestimated the material lead-time on communications couplers (that receive information from the devices in the field), which caused the completion of the substation work to be pushed to a later commissioning date than originally anticipated. This was mainly due to the Company's substation feeders being fed from reactors, which required a capacitive coupler, instead of the much more common inductive couplers. Therefore, the related equipment from the vendor was not as readily available. Even with this challenge, the project was still completed well before the three-year term-end and significantly underbudget. The budget under-run is primarily due to the Company not having full engineering and design completed during the original filing period. After vendor selection and full design, costs ended up being less than expected.

The Company leveraged the lessons learned regarding the long material lead times for this project and, for the additional investment in this category, the project team placed an emphasis on project logistics and planning. This logistical planning emphasis was beneficial and enabled the Company to successfully install and commission this additional project.

The Company also experienced a communications challenge on the second project. The field devices were to communicate back to the substation over powerline carrier ("PLC") but were affected by a short stretch of the conductors. The team was able to quickly assess the problem and develop a low-cost solution to move the communications receiving device to an area that was unaffected by the impedance.

(f) Power Quality Monitoring

The power quality monitoring program was largely successful due to the coordination and research of several internal departments to identify a local integration vendor. As a first-of-its-kind project for the Company, there were assumptions made early in the process that were validated or rejected at the program conclusion. The work methods associated with physically installing the monitoring devices originally anticipated having to take circuit and/or bus outages to complete the work. The team was able to identify a safe and effective method of installing the devices without these outages, which saved considerable time and resources, and therefore money.

The Company also developed a procedure with the I.T. infrastructure and security departments to allow for remote interrogation of the system and the ability for the system to transmit a summary email to select personnel in real-time, after a triggering event. This process provided the Company with immediate intelligence after the occurrence of a system disruption, which enabled a quick and productive discussion and/or response to larger commercial and industrial customers, whose sensitive equipment or processes may have also experienced disruption. This process will allow the customer(s) and the Company to take appropriate actions, respectively and collaboratively.

There were no significant challenges, other than typical project challenges, for this program. However, by going through the process, the Company was able to fully vet the system and will be better positioned for efficient future deployments.

14. Benefits Realized as the Result of Implementation

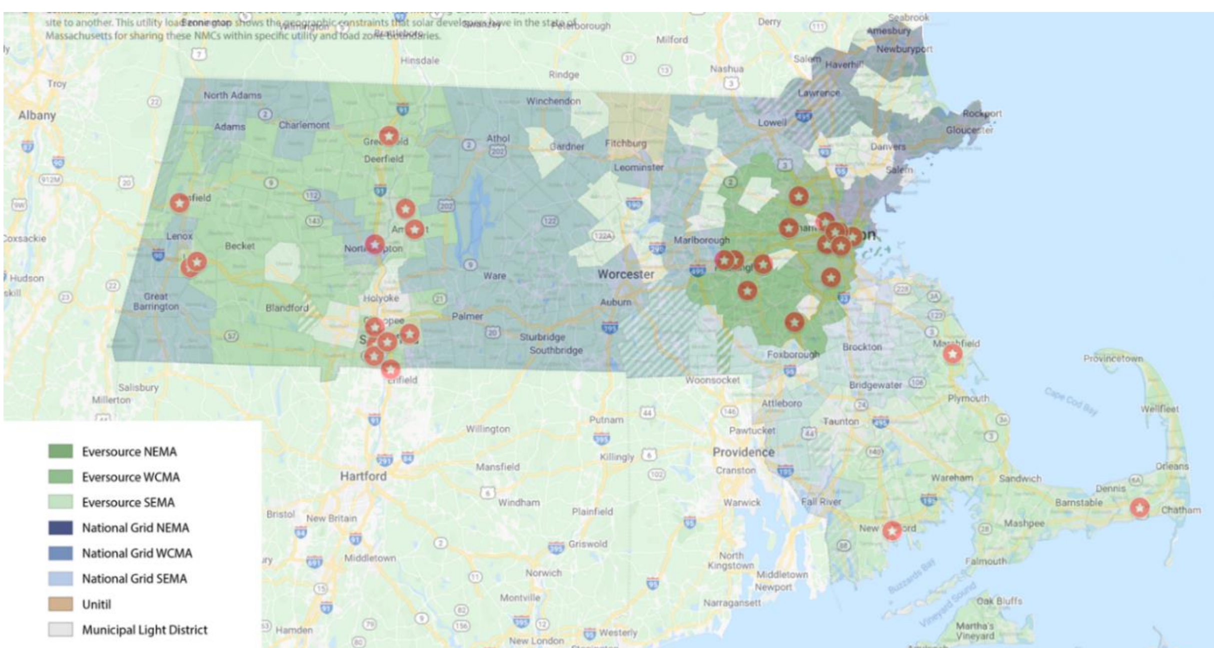
There are immediate benefits, described below, to the Company and ultimately its customers by having visibility and control of additional devices in the field, such as insight into emergent conditions, remote switching, and acquisition of load data. Additionally, the increase of the investment types identified in this section will influence several of the metrics identified in Sections IV and VI of this report and Appendix 1. For further analysis will be contained in the "Massachusetts Grid Modernization Program Year 2021 Evaluation – Monitoring and Control" report which will be provided by Guidehouse (formerly Navigant Consulting) on June 1, 2022.

The following is a summarized view of the investment benefits, which are in addition to the quantifiable metrics referenced above:

(a) Microprocessor Relays and 4kV Circuit Breaker SCADA

The microprocessor relay (15kV-class bulk substations) and 4kV circuit breaker SCADA programs are very similar in that they both add the functionality of upgraded primary and backup relays on feeders and other strategic substation locations by replacing electromechanical relays with modern microprocessor relay protection schemes. This replacement adds control, indication, and analog functionality of non-reclosing, hot-line tag, and underfrequency load shedding at distribution feeder circuit breakers at substations. These upgrades provide the Company's system operators with enhanced visibility and control of the system.

Figure 15: Locations of Substation Upgrades



The distinct difference between the two programs is that the 4kV substations had virtually no SCADA capabilities, whereas the 15kV-class bulk substations had limited SCADA capability. At the 4kV substations, the projects installed new or upgraded existing station remote terminal units ("RTUs") to add control, indication, and analog functionality at all feeder breakers, tie-breakers, and transformer secondary breakers where they did not exist. Additionally, to capitalize on the economy of scale by having all relevant engineering and installation resources on site, where possible and practical, the team integrated the substation transformer into the SCADA system to provide an even more comprehensive picture to the system operators.

The team focused on new RTU installations targeting existing 4kV Stations with inadequate communications[3] and SCADA infrastructure as many of these substations had extremely limited or no existing SCADA visibility or control of transformers. The added visibility and control of this critical equipment supports the Department's grid modernization objectives and furthers the effectiveness of the upgrades implemented by the 4kV circuit breaker SCADA program. The specific scope of each project, as related to integrating substation transformer controls, remained dependent on the accessibility of existing alarms and controls points, the vintage of the existing transformer, and the feasibility of integrating equipment to SCADA. In general, each project evaluated the ability to incorporate the following transformer alarms and controls to SCADA to the extent feasible and cost-effective:

- Load Tap Changer ("LTC") status, control, and indication
- Load Tap Position ("LTP") and Trouble alarms
- Winding and oil temperature indications
- Sudden pressure and circulating current trip indications
- Transformer bushing potentials
- Transformer metering

[3] Refer to Section III.E.1.a) for examples of where the Communications investments of limited ADSS fiber optic installations were employed to support several 4kV substations.

Figure 16: Depiction of newly installed relays (picture, left) and a combination of new and existing relays (picture, right). The existing relays in this 4kV substation were built into marble panels.

Distribution System Operator's Perspective:

The grid modernization substation programs provide the system operation centers the SCADA visibility and control of the distribution system to enable system operation, troubleshooting, and control, from the control room, whereas previously most, if not all of these efforts would have required physical resources on-site in the field in coordination with the resources in the control room. There are several benefits experienced from a protection, reliability, and situational awareness standpoint. For example:

- Less time to troubleshoot emergent system problems because the system operations center has immediate visibility of system problems and can begin to diagnose / resolve them immediately

- Resources needed to implement emergent system repairs can be dispatched immediately to address the system issues instead of being dispatched to first diagnose.

- Visibility and remote control of distribution assets prepares the system for the future where distribution management system ("DMS") load flow software can be overlayed to enable automated switching and control.

- LTC control and load sensing enables load shedding capabilities (as outlined above).

- As an example for planned outage work: When setting a breaker to "reclosing OFF," such as part of a non-reclosing assurance ("NRA") condition, for a breaker that now is now SCADA-enabled, this translates to fewer resources in the field assigned to that task and less time the circuit will have "reclosing OFF" (i.e., the breaker can now be taken off in the morning versus during the afternoon of the previous day and can be placed back "ON" in the afternoon of the same day versus during the night). Just one NRA on a SCADA-enabled breaker equates to approximately 14 hours of additional time that circuit will be placed back into the "reclosing ON" position. That is a 14-hour enhancement that keeps customers protected from outages. The aggregate sum of increased reliability when the above scenario is applied to hundreds of NRAs per year is significant.

- From a worker protection standpoint, hot line tag ("HLT") functionality operates at a much lower threshold of detecting fault current and in turn initiates a breaker sequence faster. This provides a greater threshold of protection for workers.

- From a reliability standpoint, in addition to the above, system operators have been able to find alternative switching schemes by having faulted indicators ("FI") in the field, which had been installed to support the grid modernization microprocessor relay work. The ability to evaluate and administer alternative switching from the system operations center will translate to the elimination of a significant amount of field switching, yet still maintain a feed optionality to the Company's customers (eliminating putting a customer on one line). This also provides greater flexibility for areas that can be challenging to isolate due to the volume of locations per feeder. Moving forward, these devices will continue to be used to minimize outage exposure when performing emergent or planned work, which will pay dividends for years after the grid modernization project is complete.

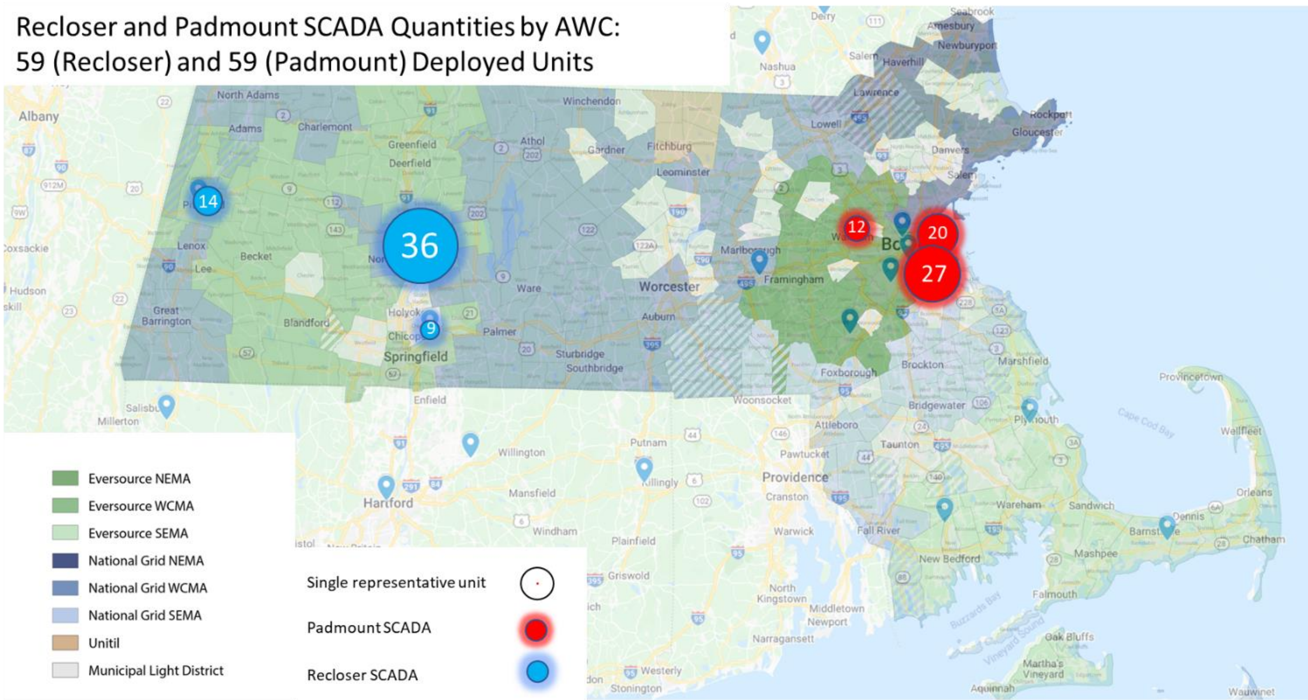
Established as part of these grid modernization investments, the system operators are now provided specific alarms grouped by Bus Lineup, which when integrated with the new feeder SCADA screens and visual dashboards, that allow the operators to determine the specific problem with the exact feeder, have more remote control of the system, and obtain better situational awareness. This will allow the system operator to better advocate for, and inform, the workers in the field as well, as more efficiently observe the system as a whole in a timelier manner. Prior to these grid modernization investments, the system operator was usually limited to a few non-specific general station trouble alarms.

(b) Recloser SCADA and Padmount Switch SCADA

The recloser and padmount switch SCADA programs were designed to be a quick and effective way to deploy communications functionality to existing devices to make them SCADA-enabled, controllable, and visible to the system operation center. As discussed elsewhere in this report, the visibility and control of field devices is an integral part to the advancing the grid modernization objectives for optimizing system performance. Additionally, the continued deployment of SCADA devices will provide immediate contributions to the future DMS by providing grid information and allowing remote command and control.

In both programs, the Company identified all locations that were feasible to upgrade and completed the work at these locations. For the recloser SCADA program, after the Company completed all of the communications-only upgrades, additional existing, non-SCADA devices were identified and a cost-effective deployment of "replace, in-place" was implemented so that the continued proliferation of SCADA-enablement could continue, while still retaining the original budget parameters. For the padmount SCADA program, once all communications-only locations were identified, which was three units short of the commitment, the "replace, in-place" process was analyzed but determined to not be cost effective, namely due to the cost of the equipment.

Figure 17: Recloser and Padmount SCADA Deployments by Area Work Center/District



(c) Network Protector SCADA

The Digital Grid platform, which is a vendor-specific technology deployed in the Network Protector SCADA investment, has provided much needed insight into the power flow analysis and transformer capacities of the Company's area networks in the WMA region, in both nominal and contingency conditions. The system has become an integral engineering tool in determining network transformer sizing and replacement, as well as helping to determine appropriate secondary conductor sizing and quantities within the network. The system sensors are also being used to determine network transformer health.

With the adoption of the Digital Grid system, additional components and sensors are being considered by Eversource to continue to improve upon visibility over network transformer health network vault conditions. See Figure 18, for a screen shot of the Digital Grid system.

Figure 18: Sample screen shot of the Digital Grid monitoring system.

Proposed Vault Sensor Input Mapping

Signal Name	GUI Flag	Connected To	Current Sensor Type	Current Attached Sensor	Future Sensor Type	Future Planned Sensor	Pigtail Wire Color
A Flag	A	NWP Relay Directly	Digital	DG-651 NWP Water Sensor	Digital	DG-651 NWP Water Sensor	N/A
B Flag	B	NWP Relay Directly	Digital	NWP Switch Position	Digital	NWP Switch Position	N/A
C Flag	C	Smart External Cable DG-280	Digital	Unused	Analog	DG-663 Transformer Main Tank Pressure	Red
D Flag	D	Smart External Cable DG-280	Digital	DG-680 Primary Switch Pressure	Analog	DG-663 Transformer Primary Switch Pressure	Yellow
E Flag	E	Smart External Cable DG-280	Digital	NWP Pressure Sensor	Analog	Spare	Orange
F Flag	F	Smart External Cable DG-280	Digital	Unused	Analog	DG-675 Transformer Main Tank Oil Level	Violet
G Flag	G	Smart External Cable DG-280	Digital	Unused	Analog	DG-675 Transformer Primary Switch Oil Level	Grey
H Flag	H	Smart External Cable DG-280	Digital	Unused	Digital	DG-652-2 Vault Liquid Level	White
Q Flag	--	N/A	N/A	N/A	Digital	NWP Pressure	N/A
A1	A1	Smart External Cable DG-280	Analog	DG-500 Vault Temperature	Analog	DG-500 Vault Temperature	N/A
A2	A2	Smart External Cable DG-280	Analog	Unused	Analog	DG-665 Transformer Main Tank Temperature	Blue
A3	A3	Internal to Relay	Analog	NWP Relay Temperature	Digital	NWP Relay Temperature	N/A

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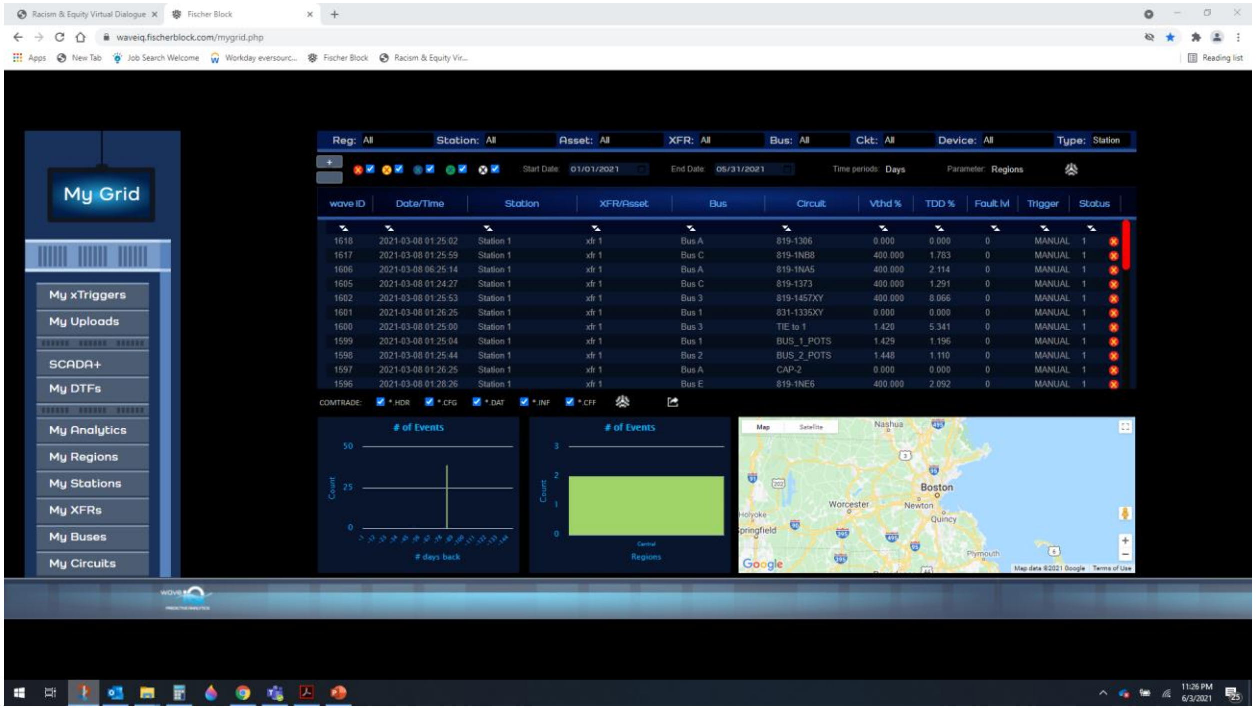
(d) Power Quality Monitoring

The focus of the initiative is providing remote access and storage of power quality meter data so that detailed information from disturbance events can be evaluated by the Company's System Planning, Protection and Controls ("P&C") Engineering, and Distribution Engineering teams and shared with customers. Access to this type of information at select substations will provide the Company with a new set of very granular data that will both increase situational awareness of disturbances and provide insights into the downstream effects.

This data collected through this investment allows for rapid post event analysis and evaluation by P&C Engineering to confirm correct protection system operations, and by the System Planning team to develop solutions, if needed, to out-of-specification voltage fluctuations that affect customers, particularly customers with sensitive load requirements. This event data can also be shared with customers to better evaluate the response of their protection, generation, and building system response to events that occur on the system. See Figure 19, for a screen shot of the Fisher Block power quality monitoring system.

Figure 19: Sample screen shot of the Fisher Block power quality monitoring system.



As an example, the output data from the power quality monitoring system after a faulted underground cable is shown in Figure 20 and Figure 21. From this data, the Company was able to discern on which phase the fault occurred and how it propagated. This data allows for sub-cycle monitoring and recording of events which, when combined with configurable triggering thresholds, provides automatic email notification to the subject matter expert personnel for both awareness and analysis. The benefits behind this automated infrastructure are that it provides the Company with insights and information needed to effectively communicate with, and/or have responses for, affected customers on the system. This collaborative approach with customers allows each respective group to understand and address power quality disturbances as appropriate.

Figure 20: Example current waveform output

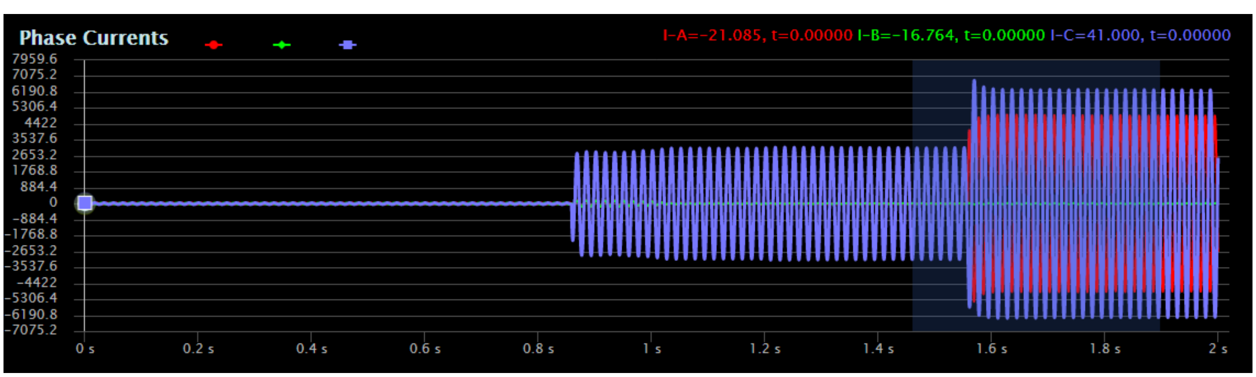
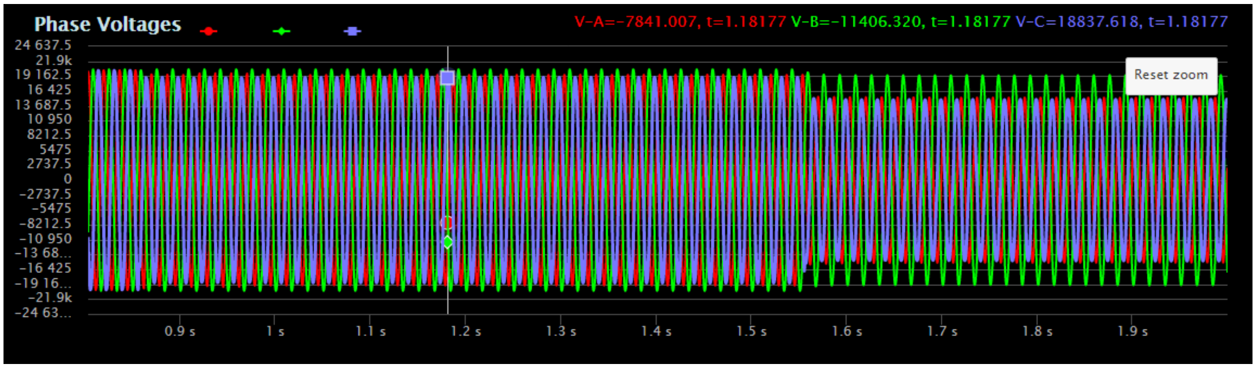


Figure 21: Example voltage waveform output



15. Description of Capability Improvement by Capability/Status Category

(a) Methodology

Microprocessor Relays: The specific relays selected for this program were based on a list of feeders and their characteristics. One characteristic was an indication if SCADA was available. Selecting non-SCADA feeders was the first pass analysis. Next, substations for which there was major (non-GMP) work scheduled but not anticipated to be completed prior to 2020 were eliminated from consideration. Next, all substations that utilized overhead reclosers serving as feeder breakers were removed from consideration. Finally, all substations with scheduled retirements were removed from consideration. What followed from this analysis was the list of substations and feeders that were determined to be good candidates for the microprocessor relay upgrades.

SCADA Switches (Recloser, Padmount, Network): Prioritization for reclosers, secondary network protectors and Padmount switches was based on the same zone size and reliability ranking methodology as described in the Distribution Automation (Section III.B.4 below). These criteria included: number of customers impacted by the device (higher); and the circuit reliability (lower). Padmount switches had an additional criterion: motorized switches were prioritized and were a requirement for investment.

Power Quality Monitoring: The substation selected for this program was based on conversations that the Company has had with larger commercial and industrial customers, with whom power quality is of particular concern due to their operations. This new system will provide further insight into the electric distribution system and will be another enabling system that will support future GMP deployments, such as the DMS.

(b) Expected Capability Improvement

Enabling Monitoring and Control (SCADA) on distribution system equipment provides Eversource with accurate minimum load data for circuit segments. This data is required for Eversource to perform load flow analysis in support of Demand Response ("DR") integration and automated feeder reconfigurations within a centralized, real-time logic system like a DMS. Additionally, and even prior to full circuit automation and integration with the GMP-driven IT systems, these new/upgraded devices will provide an enhanced level of visibility and control to the system operators.

16. Key Milestones

- All Microprocessor Relay and 4kV Circuit Breaker SCADA carry-over work was engineered and designed in 2021 and the Company has started construction in Q1, 2022.
- Recloser SCADA program was fully deployed at 160 percent of commitment.
- Padmount SCADA program was fully deployed at 95 percent of commitment but had exhausted all possible locations.
- Network Protector SCADA was fully deployed at 110 percent of commitment.
- Power Quality Monitoring project was successfully deployed and was a first-of-a-kind for the Company.

B. Distribution Automation

1. Performance on Implementation/Deployment

Refer to Figure 22 and Figure 23 below for the Company's 2018-2021 implementation unit and spending summaries for the Distribution Automation GMP Investments.

Figure 22: 2018-2021 Distribution Automation Implementation Unit Summary (# of Units)

Investment Category	Preauthorized Device Type	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2018-2021 Actual	2018-2021 Projection*	% Difference
Distribution Automation	OH DA w/o Ties	25	148	70	91	334	343	-3%
	OH DA w/Ties	0	45	8	0	53	53	0%
	4kV Oil Switch Replacement	0	89	48	35	172	172	0%
	4kV AR Loop	0	17	1	0	18	34	-47%

Figure 23: 2018-2021 Distribution Automation Implementation Capital Spending Summary ($)

Investment Category	Preauthorized Device Type	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2018-2021 Actual	2018-2021 Projection*	% Difference
Distribution Automation	OH DA w/o Ties	2,267,503	12,069,703	3,838,524	6,533,425	24,709,155	26,175,729	-6%
	OH DA w/Ties	-	2,797,738	455,052	3,026	3,255,816	3,252,790	0%
	4kV Oil Switch Replacement	932,307	13,881,098	9,189,867	6,191,485	30,194,757	29,003,272	4%
	4kV AR Loop	-	891,645	569,292	835,732	2,296,669	2,460,937	-7%

(a) Overhead Distribution Automation ("DA")

The Company originally committed to deploying 196 new reclosers as part of the 2018-2020 GMP and 100 new reclosers as part of the supplemental 2021 GMP (296 total units). Due to its efficient and effective processes and planning, the Company was able to exceed the commitment goal of 296 units by 38 units for a total deployment of 334 units. This is still short of the Company's stretch goal by nine units. The Company intend to install reclosers at an additional nine locations in Q2, 2022. These nine locations were planned for 2021, but due to a rebalancing of the Company-wide work plan, resources were over allocated in this region, and the Company did not have sufficient time to fully complete the installations. The reclosers are resourced and planned into the 2022 schedule.

As was discussed in prior Annual Reports, the OH DA program is a core capability of the Company and the efficient deployment of these devices allowed for a faster field deployment, which immediately impacts both increased visibility into the grid and reliability through automation and reduction in customer zones. The deployment of these devices continued to positively impact the Eversource Customer Outage Metrics of "Average Customer Zone Size" (see Section VI.1.14.7) and the "System Automation Saturation" metrics (see Section IV.1.2).

In addition to the positive customer benefit metrics, listed above, the Company deployed reclosers in support of a 4kV network reconfiguration the New Bedford service territory. This work was completed to increase reliability in a portion of the distribution system by cutting over from an older network system and into an overhead looped-circuit configuration. The work in this location required careful coordination for cutover and also included the need to reconfigure several nearby transformers. The net effect is expected to increase reliability and has also eliminated older equipment from the system.

The Company's original total capital costs were estimated at $19.4M for the 2018-2020 GMP and $8M for the supplemental 2021 GMP. The actual total capital costs for the deployment of 342 units, inclusive of the nine carry over units, is expected to be $26.2M. The average unit costs for this program were below the budgeted unit costs. The Company coupled the reduced unit costs and a redeployment of costs from other investments to make a material impact on additional deployments.

(b) Overhead Distribution Automation w/Ties:

The Company originally committed to deploying 38 recloser circuit-tie units for $6.3M. The Company was able to exceed the GMP goal of 38 units by 15 units for a total deployment of 53 units. These ties were generally simple circuit ties in which a manual switch was replaced with a tie-recloser. In some instances, additional reclosers were added on either side of the tie to either reduce customer counts between load or to facilitate recloser coordination. Automation of circuit tie points provides the Company with a broader array of both grid visibility and control but also optionality when reconfiguring circuits, whether manually, or autonomously.

The Company's original total capital costs were estimated at $6.3M. The actual total capital costs for the deployment of 53 units was $3.5M. The significant underrun in the original budget, even with a larger unit deployment, was due to the much lower unit cost for each location. During the original budgeting process for the program, specific sites had not yet been selected and the Company assumed there would be more complex circuit ties, which would require work such as new pole sets, reconductoring, land rights, civil site work, etc. However, after full engineering evaluation, the Company determined that sufficient GMP benefits could be obtained through the deployment of simpler circuit ties.

(c) 4kV Auto Restoration Loop:

This program originally began as the "4kV VFI Retrofit" program. The intent was to replace/upgrade existing 4kv underground switches with new vacuum fault interrupter ("VFI") switches that were both SCADA enabled and would allow for mid-point and circuit tie coordination. In late 2018 and early 2019, the Company enhanced this program by working with a vendor to develop and employ an automation system dedicated to the 4kV underground infrastructure at select locations within the metro-Boston area. The program was therefore renamed to the "4kV Auto-Restoration ('AR') Loop" program. This program was to be administered in conjunction with the "4kV Oil Switch Replacement" program and included field device upgrades and a new automation controller in the corresponding substation that would allow for decentralized automation schemes to operate, outside of the Company's existing D-200/D-20MX system. This new 4kv AR loop system was expected to be a relatively straight forward installation that would allow for immediate customer benefits, and ultimately work in conjunction with the DMS, which is the end-state solution for the entire electric system automation.

The original unit of measure of the "4kV VFI Retrofit" program was in "units," with a proposed amount of 78 units for deployment. After the switch to the "4kV AR Loop" program, the existing measure of "units" was neither applicable nor appropriate. This change was discussed in the response to Department Information Request DPU-AR-4-7 in D.P.U. 20-46, the Company's 2019 GMP Annual Report. A more appropriate unit of measure was established as "loops created." This change was primarily due to the diversity of work required in the field to obtain remote visibility and control and the accompanying substation work. As an example of this work diversity, in some field instances, a communications package was the only requirement, while in other instances an entire switch replacement was necessary. This is also why the Company dovetailed the "4kV Oil Switch" replacement program into the loops, where possible, which is also discussed in the response to Information Request DPU-AR-4-7.

In 2019, following its competitive procurement process, the Company selected a Schweitzer Electric Laboratories ("SEL") system to administer the loop logic. After much iteration, a final field and substation design was established. The Company achieved remote visibility and control of select 4kV field devices, completed the installation of the SEL distribution automation controller cabinet, and established radio and cellular communication stations with the expectation that field devices could communicate to the SEL Distribution Automation Controller ("DAC") and the SEL DAC could communicate back to the Company's SCADA system. Essentially, all construction efforts for this project were completed in 2019.

It was during the commissioning process that the Company began to experience numerous and significant issues related to effective and consistent communications between the field devices and the SEL DAC, and between the SEL DAC and the Company's SCADA system. Up until early 2020, the Company was in the process of upgrading to a new SCADA system (under a separate and non-GMP project). The decision was made by the Company to pause commissioning efforts of the 4kV AR Loop program, until the new SCADA system was commissioned and in service. The new SCADA system was brought online in late Q2 2020. At that point the communication paths between the SEL DAC and the SCADA front-end processors were commissioned into service. However, the challenges remained in establishing the direct and consistent communications from the field devices to the SEL DAC.

There are three main options that the Company could have chosen as communication methods to the field devices:

1) Fiber optics: The use of fiber optics is the most robust technology to utilize in this situation. However, there is no existing fiber optic infrastructure in this area of the distribution system and installing fiber optics to these locations was determined to be cost prohibitive.
2) Private and/or public radio: The use of private or public radio infrastructure could also be an efficient means of communication. But it, too, was determined to be cost prohibitive because the infrastructure, such as base radio stations and underground to overhead antennas at each location, were not available.
3) Public cellular network: The use of the existing public cellular network, via Verizon, as the mechanism to communicate from the field devices back to the SEL DAC system. Each field location would utilize a cellular capable modem to communicate.

As the only feasible communications option, the Company used the public cellular network as the form of communication. However, this technology has limitations. These limitations were namely the consistency and strength of signal from underground locations, and the ability to receive multiple polled data sets from the field devices and into the SEL DAC, simultaneously.

The consistency and signal strength at each field location could be impacted by conditions above the manhole such as snow and ice, large vehicles, construction activity, or other typical events/conditions that reduce cellular connections such as are experienced on personal cell phones. Additionally, the ability for the base radio station, collocated with the SEL DAC, experienced difficulty with receiving multiple and simultaneous data set transmissions from the field devices. These "collisions" of data prevented the system from accurately analyzing the data.

The Company worked to resolve each of the above, and various other challenges. In many cases the issues were resolved, and the program moved forward, albeit with an extension of schedule and increased costs. However, as the Company approached the end of the 2018-2021 GMP term, the decision was made to terminate the 4kV AR Loop program based on three key reasons:

1) The Company's DMS program was underway and accelerating in deployment. The Company expects that the DMS will be able to provide the majority of the functionality and customer benefit of the 4kV AR Loop program using a centralized automation logic.
2) Though many challenges and issues had been resolved, there was still uncertainty with the resolution of the remaining issues of communications consistency and data collision avoidance.
3) The Company is sensitive to both the program costs and the utilization of its internal and external resources and ensured that the highest priority projects were being executed.

The Company recognizes the importance of developing advancements in the 4kV underground system and will continue to drive to a solution in a cost-effective manner. However, these efforts must be balanced across costs, resources, and customer benefits. As discussed above, the Company is not abandoning system upgrades to the 4kV system but has instead reprioritized the deployment for the DMS over the 4kV AR Loop. Lastly, though the program is being terminated, the work completed at the various field switch locations to enable SCADA communications will be retained as they provide an enhancement to the system regarding visibility and control.

The Company's original total capital costs were estimated at $4.3M. The actual total capital costs for the deployment of the SEL system, and various field device and communications upgrades is $2.3M. As discussed in prior GMP Annual Reports and in response to Information Request DPU-AR-4-7 in D.P.U. 20-46, the spending is not reflective of the original deployment strategy, due to the change in program function.

The principles and premise of the GMP is to advance and modernize the electric power system. In many instances this involved utilizing new and untested technologies. Though typically successful, this program is an example of a technology that proved to be inconsistent with an increase to customer benefits in accordance with the GMP objectives and an acceptable cost. With the exception of the field devices, which were upgraded to be SCADA enabled and are currently providing benefits, the Company has determined that it is appropriate to seek recovery of the expense associated with this program in a future GMF filing.

(d) 4kV Oil Switch Replacements

The Company originally committed to deploying 105 VFI switches to replace 4kV oil-filled units as part of the 2018-2020 GMP and 35 VFIs as part of the supplemental 2021 deployment plan (140 total units). The Company exceeded the commitment goal of 140 units by 32 units for a total deployment of 172 units. This was a significant undertaking and the lessons learned throughout the program were fully employed in order to make the execution successful. The immediate deployment of devices in 2018 and the aggressive workplan in 2019 allowed the

Company to quickly mature its execution of this program, which resulted in additional units being deployed and enabled the Company to respond to the COVID-19 restrictions that heavily impacted this program's plan, most specifically in Boston. The ability to effectively coordinate across various Company departments was instrumental in executing an aggressive GMP. This is particularly true with the execution complexity of working within the 4kV underground system. To aid this process, the Company provided specific points of contact in the form of a taskforce for execution. After the initiation of the program in 2018 and once the bottle necks and challenges were identified and corrected, the Company maintained the execution momentum for the remainder of the term.

The Company's original total capital costs were estimated at $13.7M for the 2018-2020 GMP and $5M for the supplemental 2021 GMP. The actual total capital costs for the deployment of 172 units was $30.2M. The total capital spend for this program is higher than originally budgeted because the Company executed a stretch goal plan and commissioned significantly more switches than originally projected. Additionally, the average unit cost was higher than budgeted with a high degree of variation across work locations. These variations include: (1) the complexity of the electrical outages; (2) ensuring minimization of customer disruptions, which may have included the use of temporary generation equipment; (3) the distance between manhole locations and the number of personnel needed; (4) traffic control; and (5) condition of the existing work locations. The Company determined that it was prudent to accelerate this program and add additional units, even with the higher-than-expected unit costs, in order to capitalize on processes and momentum that was developed.

17. Lessons Learned/Challenges and Successes

(a) Overhead Distribution Automation

The OH DA program contains typical device installation that is consistent with the Company's experience in installing devices on its system. Given that the Company had processes and procedures in place to address these types of installation, it was efficient in leveraging those processes to set up and undertake these incremental GMP investments. Overall, this program was very successful in both efficiency and installation cost savings.

The Company had identified commissioning resources as a potential shortfall in resources. The emphasis that that Company placed on planning and monitoring for the Commissioning team enabled them to develop and implement achievable yet aggressive plans. Continuous communication and situational awareness were the key factors in achieving the Company's objectives under the OH DA program.

A grouping of 20 reclosers in the Company's South region was installed in order to cutover these circuits from an older network into a radial/loop configuration. The Company had expected to install these units and allow them to coordinate together without further work. However, after recloser implementation and commissioning, it was determined that several, smaller, local substations also required upgraded protection and control settings to ensure the reliable and safe operation of the new devices. This development occurred late in 2019. The Company made the decision to take these 20 new reclosers offline until all remaining substation settings work could be completed in early 2020.

(b) Overhead Distribution Automation w/Ties

This Company's experience with this program was very similar to its experience with the OH DA program discussed above and the Recloser SCADA program discussed in Section III.A.

One of the lessons learned from the program onset was the need to closely coordinate OH DA, OH DA with Ties and Recloser SCADA work undertaken by the Company's Protection and Control engineering teams. Such close coordination is necessary because any changes in automated, switchable devices in a circuit will affect the coordination aspects for all remaining devices on that circuit. Therefore, if each of the aforementioned investment types had been completed independently of each other, there would have been constant and inefficient engineering rework to achieve the necessary coordination between these investments. The holistic approach that the Company implemented and the rigor that was placed on program oversight and communication prevented this potential inefficiency.

(c) 4kV Auto Restoration Loop

As previously discussed, the 4kV automation had never been implemented by the Company prior to the commencement of the 2018-2021 GMP in 2018. As with any new technology implementation there was a learning curve. Specific to this investment was the challenge of finding the correct blend of communications infrastructure, compatible equipment, and relevant customer counts, so as to have a meaningful reliability improvement for as many customers as possible. This was further compounded by the need to iterate the loop system design to be able to determine the correct blend of infrastructure and equipment. The search to find adequate substations that did not require substantial upgrades to account for communications infrastructure or compatible equipment resulted in the design associated with this program commencing later than expected. This schedule delay placed significant pressure on the Company's commissioning teams because their established execution plan was both shifted and inconsistent due to unforeseen issues that arose. This work then overlapped with other planned work creating a resource shortage.

Once the design of the system was completed, the most significant lesson learned was the need to have a detailed survey of prospective substations. Identifying the right set of substation conditions was a challenge.

There is an iterative process required when deploying new technology, and the need to provide better assessments and resource needs at project onset is critical but very difficult. Specifically, the Company's current planning and execution structure is set up to construct infrastructure with a complete set of design specifications. In a new technology deployment situation such as the AR loops, it is important that relevant personnel understand that a project of this nature will not have a fully executable design and that the process will involve trial and error, with some/many challenges along the way. It is also critical that Company personnel have the necessary resources to aid them in the build and refinement process.

Another lesson learned is the level of effort and design that was needed based on using different types of communications structures. This program would have benefited from a fully deployed fiber optic communications infrastructure. The Company's communication structures in this area are not built out with that type of high-speed access. Therefore, the Company's plan included the use of a radio/cellular network. The use of these technologies is practical but also comes with inherent and unforeseen conditions.

(d) 4kV Oil Switch Replacements

The replacement of the underground 4kV oil switches is a complex process. The challenge is due in part to the high customer density and the electrical outage boundaries that need to be established in order to perform the work. Plan years 2019 and 2020 saw the most significant deployments. The teams responsible for these replacements continued to:

- Closely coordinate, so that the work could be planned and executed as efficiently as possible to limit the extent and duration of the planned outage. The teams accomplished this balance by planning as much maintenance and/or non-GMP work as possible to be undertaken during the outage. The teams ensured that GMP work was maintained separately (administrative/financially) from the other work. The specific GMP work and cost tracking processes developed to implement the GMP consistent with the Department's directives were followed in order to maintain this strict separation.

- Avoid having to schedule a second planned outage. The teams identified all of the GMP switch locations in advance so that, if a planned/emergency outage were to occur in the affected zone of a GMP location, the installation team could work to install the GMP device at the same time as undertaking the work to address the initial outage. The team followed all cost tracking processes to ensure that the GMP and non-GMP costs were tracked and recorded separately.

- Be prepared if an emergency outage occurred in the 4kV underground system. If an oil switch was identified as being within the electrical outage boundaries and could be efficiently replaced without extending the existing outage, crews would react quickly to replace the oil switch. The decision to complete GMP work in this manner was evaluated on a case-by-case basis to determine the merits of extending the existing outage to install the GMP device versus requiring a second, separate outage to install the device. The crew's supervisor and management teams carefully reviewed field work charging to ensure that costs were maintained separately from the outage event, and that outage event costs were not included in the oil switch replacement. This was a very effective process and prevented customers from experiencing a future, planned outage, in order to remove the oil switch.

By having an aggressive deployment in the 2019 plan year, allowed for fewer installations in 2020 while still allowing the Company to meet the original three-year term commitment. Having fewer units to install allowed the team a buffer, to first understand, and then accommodate the challenges and restrictions of the COVID-19 pandemic.

The replacement of the 4kV Oil Switch Replacements involved many departments. The cross coordination of these departments was critical and in order to meet the program commitments, the Company placed one specific manager to be in charge of the program and ensure consistency and efficiency throughout the deployment.

Pre-checking a job location ahead of deployment is a standard process, so that the field personnel can be prepared for the work. However, due to the age and location of many of these devices, unforeseen conditions often arose, such as collapsed ductwork, fragile slices, stubborn connections, and street closing permit restrictions added to the complexity.

18. Description of Benefits Realized as the Result of Implementation

There are immediate benefits to the Company of having visibility and control of additional devices in the field, such as insight into emergent conditions, remote switching, and acquisition of load data. Additionally, the increase of the investment types identified in this section positively affected several of metrics identified in section IV and VI of this report and the Appendix 1 attachment. Specific examples include:

- At the end of the 2018-2021 GMP, the System Automation Saturation Infrastructure Metric, which is described further in Section IV of this report, indicated an 85.0 improvement over the baseline period. While this metric was designed to capture automation improvements both under the GMP and pursuant to other system investment outside of the GMP, a significant portion of the 85.0 improvement would not have been possible without the GMP investments. For example, as shown in the Figure 24 below, the baseline automation saturation score for circuit 488-H6 was recorded as 728.0. At the end of the 2018-2021 GMP, the Company recorded an automation saturation score of 392.9 for this circuit. The 335.1 improvement on the automation saturation score on this circuit was driven by the Company's OH DA program. The Company deployed three OH

DA devices on this circuit during the four-year term. The Company also deployed one Padmount Switch SCADA on this circuit. The circuit level deployment for each preauthorized device type can be found in Appendix 1.

Figure 24: Specific Example of the Saturation Score (before/after) GMP Investment

	Circuit	Customer Count	Total Feeder Automation Score	Total Automation Saturation Index (B) / (C)
Baseline	488-H6	3,276	4.5	728.0
2021 Results	488-H6	3,340	8.5	392.9
Change			*4.0*	*-335.1*

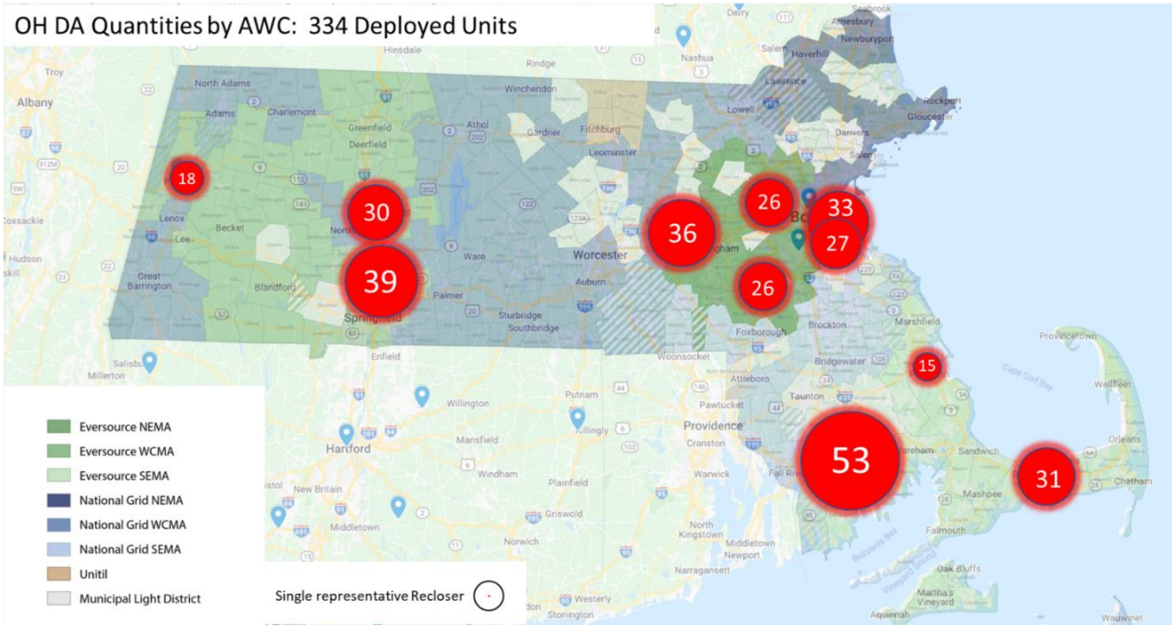
- At the end of the 2018-2021 GMP, the Eversource Customer Outage Metric, which is described further in Section VI of this report, indicated the average circuit zone size decreased to 285 customers. This represents a reduction of 74 customers over the baseline period.

- At the end of the 2018-221 GMP, the Eversource Number of Customers that Benefit from GMP funded DA Devices Metric, which is described further in Section VI of this report, indicated over 249,000 customers benefited from GMP funded DA Devices. These customers were spread across more than 170 circuits and represented approximately 14 percent of all customers in the Company's territory. More details can be found in Appendix 1. The reliability-related performance metrics, as defined, proved difficult to measure for several reasons, which are detailed in Section VI of this report. Due to this challenge, the Company worked with Guidehouse to perform case studies to better evaluate the benefits of GMP devices. Case studies on GMP DA devices were performed using data from the outage management system ("OMS"), switching orders, SCADA data, and circuit diagrams. With this information, Guidehouse evaluated specific outage events and estimated the impact GMP DA devices had on those specific events. The case studies demonstrated that GMP DA devices yielded benefits related to reduced and/or avoided customer outages as well as safety-related benefits. Detailed case studies on GMP DA devices can be found in Guidehouse's Massachusetts Grid Modernization Program Year 2020 Evaluation Report: Advanced Distribution Automation (ADA).

(a) Overhead ("OH") Distribution Automation ("DA")

The OH DA program was an accelerated deployment of new recloser devices, which immediately and effectively reduce specific and average customer zone sizes (see Section VI.A.1.14.7). The Company is very efficient at designing and deploying these devices and therefore was able to exceed its investment commitments. The map inFigure 25 indicates deployments arranged by their respective area work center/district.

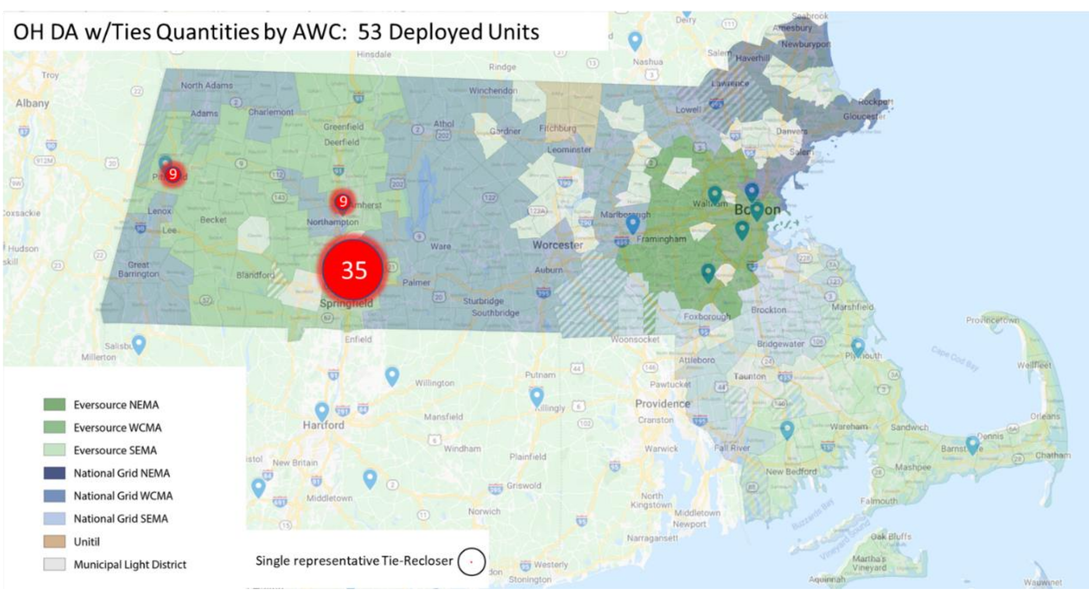
Figure 25: OH DA (Recloser) Deployments by Area Work Center/District



(b) OH DA w/Ties:

The OH DA, with ties, program was deployed exclusively in the Company's western region where there was opportunity to effectively and efficiently deploy simple ties, which are fully SCADA enabled ties that did not required significant ancillary work, such as line extension. The Company exceeded its investment commitments and the map in Figure 26 indicates the deployments, which were focused within the Springfield area work center/district.

Figure 26: OH DA with Ties (Recloser) Deployments by Area Work Center/District



(c) 4kV Auto Restoration Loop:

As discussed in Section III.B.1.c), the 4kV auto-restoration loop program will not be fully commissioned as intended. The original benefits anticipated through this program were the increased, autonomous circuit reconfiguration for the 4kV underground system in the greater Boston area. Additionally, this was a decentralized deployment of system automation, which is a departure from the Company's typical configuration. The decentralization was an effort to test the feasibility of dis-locating automation systems.

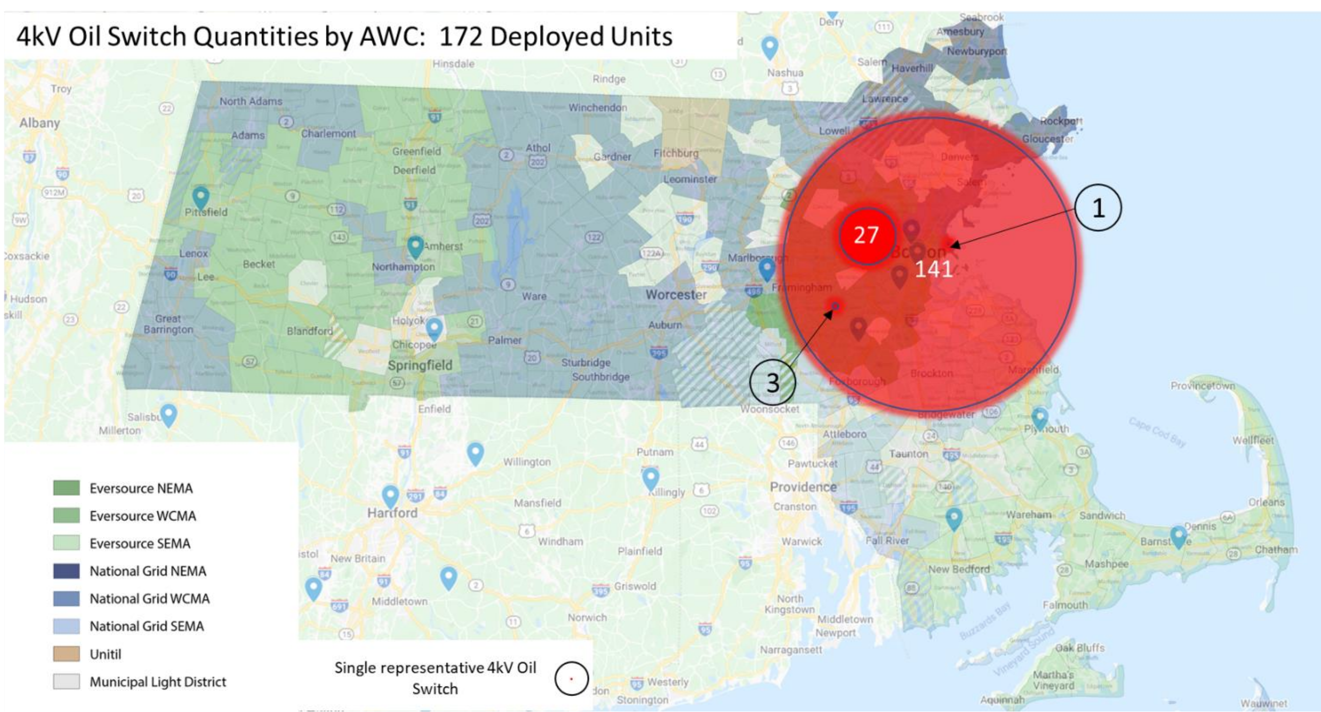
Though the system as a whole will not be placed online, the Company is reviewing the feasibility of repurposing parts of the project work that had been installed for GMP or non-GMP uses. This reconciliation will be document in future reports, including the grid modernization factor filing(s).

(d) 4kV Oil Switch Replacements

The 4kV oils switch replacement program was an accelerated deployment to eliminate older, oil-filled equipment without SCADA and install new VFI that are fully SCADA-enabled. The Company exceeded investment commitments and the map shown in

Figure *27* shows that these deployments were focused on the downtown Boston area, with additional deployments in the underground system in the Waltham/Walpole area.

Figure 27: 4kV Oil Switch Replacements by Area Work Center/District



For further analysis, refer to "Massachusetts Grid Modernization Program Year 2021 Evaluation Report – Advanced Distribution Automation" which will be provided by Guidehouse (formerly Navigant Consulting) on June 1, 2022.

19. Description of Capability Improvement by Capability/Status Category

(a) Methodology

To prioritize circuit investment, each circuit was analyzed to identify existing isolation segments or zones. Zone sizes were determined by the number of customers impacted in each zone. The Company prioritized zones with customers greater than 500 for WMA (former WMECO service territory) and 1,000 for EMA (NSTAR Electric service territory). The Company also considered circuit reliability based on historical System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") from 2016, 2017 and 2018 when selecting circuits for investment. The poorer the reliability of the circuit, the higher priority the circuit and its associated zones received. The Company applied a weight of 60 percent to zone size and 40 percent for the reliability score and then normalized on a 1 to 100 scale, with 100 being the highest priority for investment. Zones were ranked separately between EMA and WMA. For feeders that lack alternate supply sources, infrastructure was built where cost-effective to tie radial circuits and deliver the benefits of automation. Existing circuit ties were bolstered to increase their back-up capability where it was cost-effective.

The Company selected OH DA with Circuit Tie locations using a list of radial zones with existing manual three-phase tie equipment installed. Circuit reliability performance and number of customers within the zone were then used as factors to prioritize each zone for the addition of DSCADA enabled, automatic sectionalizing equipment. Radial zones without a manual alternate source were not considered as viable options for this project.

In siting the investments for automating and upgrading the existing 4kV switching, sectionalization and SCADA infrastructure, the Company focused on the Greater Boston and Cambridge areas. The current existing 4 kV sectionalization, which is a critical component of the system serving high-density residential and commercial areas, was installed in the period of 1920-1940, making it the least modernized portion of the Company's distribution system. The investment consists of replacing existing switches with the latest technology and SCADA, so these devices have similar functionality as their overhead counterparts.

The Company prioritized GMP investments in 4kV switches using the same zone size and reliability ranking methodology as described above for the overhead circuit.

The 4kV AR Loop program was terminated prior to commissioning, as discussed in Section III.A.1.c above, but the selection criteria during project development was based on the related substation having a long-range plan of staying at the 4kV operating voltage and in addition to having sufficient space for the new SEL DAC and telecommunications equipment and compatible

RTUs/Real-Time Automation Controllers ("RTACs") and relays. In addition to the substation criteria, the team looked for areas: 1) with a high density of exiting field switches that could be used as-is, replaced, or upgraded; 2) where there are underground switches that are difficult to access (since the AR Loops will help prevent manual entries); and 3) with high customer impact such as large customer concentrations or important infrastructure.

(b) Expected Capability Improvement

DA technology will allow the grid to sense the existence of a fault, automatically isolate it to the smallest possible segment and then restore service to all customers outside the faulted zone potentially with supply from alternate sources. By decreasing the number of customers in each segment between sectionalizing automated devices, the Company can reduce the impact of outages. With this added sectionalization and tie capability, the grid will dramatically increase its ability to reconfigure itself based on systems conditions. In the case of outages during major events, e.g., storms, these DA investments will reduce the duration and extent of the storm events and can result in meaningful benefit to customers.

In addition to these benefits, the automated devices in the field will reduce the amount of day-to-day manual switching operations which occur as a normal part of maintaining the electric system and adding new customers. From a system planning perspective, the enhanced flexibility to shift load based on prevailing conditions has the potential to defer capital upgrades.

20. Key Milestones

- OH DA program was fully deployed at 113 percent of commitment and the Company will continue to deploy the remaining nine units of the stretch goal in 2022.
- OH DA with Ties program was fully deployed at 140 percent of commitment.
- 4kV Auto-Restoration Loop program execution was determined to be inconsistent with the cost-benefit which was originally expected and therefore terminated.
- 4kV Oil Switch Replacement program was fully deployed at 123 percent of commitment.

C. Volt-VAR Optimization ("VVO")

1. Performance on Implementation/Deployment

Refer to Figure 28 and Figure 29 below for the Company's 2018-2021 implementation unit and spending summaries for the VVO GMP Investments.

Figure 28: 2018-2021 VVO Implementation Unit Deployment Summary (# of Units)

Investment Category	Preauthorized Device Type	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2018-2021 Actual	2018-2021 Projection*	% Difference
Volt-Var Optimization	VVO - Regulators	0	69	27	1	97	144	-33%
	VVO - Capacitor Banks	0	71	3	0	74	106	-30%
	VVO - LTC Controls	4	4	0	0	8	12	-33%
	VVO - Line Sensors	0	189	0	16	205	229	-10%
	VVO - IT Work	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Microcapacitors	0	0	99	55	154	299	-48%
	Grid Monitoring Line Sensors	0	0	111	151	262	411	-36%

Figure 29: 2018-2021 VVO Implementation Capital Spending Summary ($)

Investment Category	Preauthorized Device Type	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2018-2021 Actual	2018-2021 Projection*	% Difference
Volt-Var Optimization	VVO - Regulators	-	2,375,328	1,631,621	(20,208)	3,986,740	6,061,931	-34%
	VVO - Capacitor Banks	-	2,548,685	311,402	711,710	3,571,796	2,860,086	25%
	VVO - LTC Controls	377,157	1,044,867	30,253	125	1,452,402	2,397,267	-39%
	VVO - Line Sensors	-	678,782	556,053	197,862	1,432,698	1,234,836	16%
	VVO - IT Work	-	1,159,861	1,468,664	48,755	2,677,280	2,628,525	2%
	Microcapacitors	-	-	750,675	364,441	1,115,116	2,250,675	-50%
	Grid Monitoring Line Sensors	-	-	-	592,053	592,053	1,500,000	-61%

(a) Regulators

The Company originally committed to deploying 105 VVO regulator as part of the 2018-2020 GMP and 33 VVO regulators as part of the supplemental 2021 deployment plan (138 total units). Note that the Company treated each individual regulator as a unit. In some instances, a location would have one unit (for single phase), and in other instances a location may have three units (for three-phase).

During the engineering process for the original 2018-2020 GMP, the Company determined the total number of voltage regulators needed to achieve full VVO functionality was 96 units, a decrease relative to the original estimate of 105 units. The Company successfully completed the deployment of the 96 regulators in 2020. During the deployment of the VVO regulators, the Company experienced two significant issues. The first was the need to amend the installation standards for the largest set of three-phase regulators (540A regulators). This large regulator installation was determined to require additional support than what was called for in the Company's design specifications. This new specification added cost and time to the program and also required an upgrade to several locations that had been installed under the original standard. The second challenge was with permitting the installation of the larger regulators. Some of the regulator sizes can be quite large and therefore often meet with more resistance from the community during the permitting process. This was especially true of the platform style regulators that were discussed above. Though generally successful, the engineering personnel had to proceed through multiple iterations of design locations in order to accommodate the installations and the community, while still being effective within the VVO system.

During the engineering process for the supplemental 2021 deployment plan, the Company determined the total number of voltage regulators needed to achieve VVO functionality was four units, a decrease relative to the original estimate of 33 units. The Company was able to only deploy one of the regulators during 2021 due to drastic lead-time extension of the equipment from ~50 weeks to ~100 weeks. The Company intends to install the remaining three regulators in 2022 but installation will be dependent on the delivery of the equipment. The rationale for the reduction in regulators was purposeful, as the engineering team worked to reduce the regulators due to the challenges discussed above. The team was able to reduce the regulators significantly, while retaining VVO output objectives.

The total number of installed regulators that will be installed is 100 units, of which 97 are already completed.

The Company's original total capital costs were estimated at $2.3M for the 2018-2020 GMP and $1.2M for the supplemental 2021 plan. The actual total capital costs for the deployment of 100 units, inclusive of the three carry over units, is expected to be $3.2M. Due to additional work required to install, and in certain instances upgrade, the larger 548A platform regulators, the Company anticipated that the average unit installation costs would increase. Increased unit costs are also a result of a greater number of unanticipated field site visits during final commissioning efforts.

(b) Capacitors

The Company originally committed to deploying 84 new VVO capacitors as part of the 2018-2020 GMP and 25 new reclosers as part of the supplemental 2021 deployment plan (109 total units). During the engineering process for the original 2018-2020 GMP, the Company determined the total number of capacitor banks needed to achieve full VVO functionality was 74 units, a decrease relative to the original estimate of 84 units. The Company successfully completed the deployment of the 74 capacitors by year end 2020.

During the engineering process for the supplemental 2021 deployment plan, the Company determined the total number of capacitor banks needed to achieve VVO functionality was 25 units, which was on target with the filed estimate. The Company was on track to complete all remaining capacitor installations in 2021. However, upon taking delivery of the equipment from the vendor in Q3/Q4 of 2021, the Company determined that the vendor inadvertently provided an incorrect voltage class for one of the capacitor components and therefore installations could not be completed. Discussions with the vendor revealed that the correct equipment would not be available until at least late Q1, 2022. Upon receipt of the correct equipment, the Company will immediately deploy all remaining 25 capacitors.

The total number of installed capacitors that will be installed is 99 units, of which 74 are already completed.

The Company's original total capital costs were estimated at $2.8M for the 2018-2020 GMP and $1M for the supplemental 2021 plan. The actual total capital costs for the deployment of 100 units, inclusive of the three carry over units, is expected to be $4.1M. The total capital spend for this investment is above budgeted unit costs. Increased unit costs are a result of unanticipated work due to both a greater number of field site visits during final commissioning efforts, and a firmware reconfiguration at each site that resulted as a change to the vendor's product after the Company had performed installations.

(c) Line Sensors

The Company originally committed to deploying 140 new VVO line sensors as part of the 2018-2020 GMP and 40 new line sensors as part of the supplemental 2021 deployment plan (180 total units). During the engineering process for the original 2018-2020 GMP, the Company determined the total number of line sensors needed to achieve full VVO functionality was 189 units, an increase relative to the original estimate of 140 units. Based on this engineering and design work, the Company determined that additional line sensors would be required to provide telemetry for the VVO software to optimize voltage on the program feeders. The Company successfully completed the deployment of the 189 line sensors by year end 2020.

During the engineering process for the supplemental 2021 deployment plan, the Company determined the total number of line sensors needed to achieve VVO functionality was 36 units, which was just under the target of 40 units in the filed estimate. The Company was on track to complete all remaining line sensor installations in 2021 but ran into a material delay that pushed the installations into Q2 of 2022. Upon equipment receipt, the Company will immediately deploy all remaining 20 line sensors.

The total number of installed line sensors that will be installed is 225 units, of which 205 are already completed. The Company treated each individual sensor as a unit, with some locations having one unit for single phase and other locations having three units for three-phase.

The Company's original total capital costs were estimated at $1.4M for the 2018-2020 GMP and $0.2M for the supplemental 2021 plan. The actual total capital costs for the deployment of 225 units, inclusive of the 20 carry over units, is expected to be $1.6M. The total capital costs for this investment are averaging lower than the originally budgeted unit costs, which was a blend of end-of-line sensors (more expensive) and feeder-head sensors (less expensive), because the cost of the feeder-head sensor was less than budgeted and there ended up being more of these deployments, rather than the end-of-line sensors. The end-of-line sensor solution required a unique piece of equipment that the Company worked with the vendor to develop. The Company identified opportunities to lower the cost of this new piece of equipment by avoiding low-value features such as a battery back-up. In an effort to lower total cost, the Company limited the deployment of end-of-line sensors and used Aclara line sensors whenever possible.

(d) LTC Controls

The Company originally committed to deploying 10 LTC controls as part of the 2018-2020 GMP and four LTC controls as part of the supplemental 2021 GMP deployment (14 total units). During the engineering process for the original 2018-2020 GMP one of the original planned substations did not pass part of the planning criteria and therefore two of the LTC control units were removed from the plan. Additionally, during the engineering process for the supplemental 2021 deployment plan, the Company determined that no additional LTC controls were needed to support two additional substation and feeder deployments.

The total number of installed LTC controls is eight units, which were all completed in early 2020.

The Company's original total capital costs were estimated at $0.6M for the 2018-2020 GMP and $0.7M for the supplemental 2021 GMP. The actual total capital costs for the deployment of eight units is $1.5M. The total capital spend for this investment indicates a significantly higher than budgeted unit cost as related to the 2018-2020 GMP budget. The primary drivers of the unit costs increases were the need to perform some work with internal resources on overtime and the need for higher cost specialized external contractors. The unit costs were amended in the supplemental 2021 GMP budgets, though the budget was ultimately not required.

(e) VVO IT

The Company originally committed to deploying the VVO IT system, which was the Eaton Yukon Integrated Volt-Var Control ("IVVC"), as part of the 2018-2020 GMP.

The Company executed the procurement, installation, and commissioning of the VVO software and hardware components in three physical environments (Development, Pre-Production, and Production). This system was placed online in late 2020 and also included system configuration, database builds, and testing. Measurement and verification testing commenced immediately and has extended through until summer 2022.

The Company's original total capital costs were estimated at $6.7M for the 2018-2020 GMP. The actual total capital cost for the deployment was $2.7M. The primary drivers of the budget underrun were lower than expected software costs and implementation of a more efficient work plan for the model build process.

(f) Microcapacitors

The Company did not have an original commitment to deploying microcapacitors as part of the 2018-2020 GMP but did add 200 microcapacitors as part of the supplemental 2021 GMP deployment (200 total units). However, mid-way through the initial 2018-2020 VVO deployment, the Company determined that adding microcapacitors to VVO system would provide for additional performance. The Company utilized funds from other underrunning VVO budgets to support the deployment of 99 microcapacitors in 2020.

The Company set a target of 200 microcapacitors to be installed as part of the supplemental 2021 GMP deployment. As of the year-end 2021, 55 units had been installed. The Company was on track to complete all microcapacitor installations in 2021 but experienced an equipment delay that pushed the installations into 2022. The Company is working with the vendor to solidify new ship dates. Upon equipment receipt, the Company will immediately deploy all remaining 145 microcapacitors.

The total number of installed microcapacitors is 154 units.

The Company's original total capital costs were estimated at $0.0M for the 2018-2020 GMP and $1.0 M for the supplemental 2021 GMP. The actual total capital costs for the deployment of 299 units, inclusive of the 145 carry over units, is expected to be $2.3M, of which the 2020 deployment costs were accounted for by under-running budgets in other VVO investments. There was no pre-determined unit cost that was included as part of the original plan other than vendor quotes and installation estimates. The Company is experiencing that the unit costs, on average, run higher than expected but at a reasonable cost for the benefit increase.

(g) Grid Monitoring Line Sensors

The Company did not have an original commitment to deploying grid monitoring line sensors as part of the 2018-2020 GMP but did add 300 grid monitoring line sensors as part of the supplemental 2021 GMP deployment (300 total units). However, during program reviews of the 2018-2020 investment deployments, the Company determined that adding grid monitoring line sensors to the distribution system would provide for additional insights into key areas of the grid for both the Company's system operators and as input points for future information technology/operational technology ("IT/OT") systems. The Company utilized funds from other underrunning VVO budgets to support the deployment of 111 gird monitoring line sensors in 2020.

The Company set a target of 300 grid monitoring line sensors to be installed as part of the supplemental 2021 GMP deployment. As of the year-end 2021, 151 units had been installed. The Company encountered a resource challenge due to mid-year change in work plan that pushed these installations into 2022. The Company is continuing to deploy all remaining 145 grid monitoring line sensors in 2022.

The total number of installed microcapacitors is 154 units.

The Company's original total capital costs were estimated at $0.0M for the 2018-2020 GMP and $1.0M for the supplemental 2021 GMP. The actual total capital costs for the deployment of 299 units, inclusive of the 145 carry over units, is expected to be $2.3M, of which the 2020 deployment costs were accounted for by under-running budgets in other VVO investments. There was no pre-determined unit cost that was included as part of the original GMP other than vendor quotes and installation estimates. The Company is experiencing that the unit costs, on average, run higher than expected but at a reasonable cost for the benefit increase.

21. Lessons Learned/Challenges and Successes

Throughout GMP 2020 and 2021, the Company observed drastic increases in material lead times due to material shortages, which caused delays in the installation schedule. Installation delays affected both initial installment of devices, as well as maintenance of the current system. For maintenance, local material stock was utilized when possible, however the Company worked to find alternatives and incorporate any material delays into the schedule so as to not deplete future reserves. Revised schedules were constructed to incorporate material delays and the Company will complete construction and commissioning for all remaining GMP devices within the 2022 project year.

(a) Regulators

Since the VVO program is a new initiative for the Company, it took additional engineering time to locate and design the specific field components. The Company completed the engineering for the original 2018-2020 GMP regulator locations in late 2018. For all but the largest-sized regulators, installations were quick and efficient. However, for the larger 548A platform regulators, the Company experienced two challenges. First, due to the physical size of these devices, any new locations were required to be sited through the respective town's planning department consistent with the town's requirements, including a public hearing. For many locations, this process was conducted on a normal schedule, but in several locations, the planning and permitting process was very lengthy. Second, prior to construction, the Company identified the need to revisit the design standard for large, platform-mounted voltage regulators to increase resiliency. As a part of this process, the Company performed a full review of the installation process, which caused delays in installation. A revised design standard was published in Q1 2020, and the Company completed construction and commissioning for all remaining GMP voltage regulators based on the new requirements in 2020. The Company will endeavor, in future GMPs, to utilize different equipment/technology that will enable the regulator function but at a significantly smaller and less obtrusive size.

As a part of the quality assurance review process, the Company identified, in a limited number of circumstances, factory-caused communication and wiring discrepancies that needed to be addressed prior to commissioning into the central VVO software. This is often the consequence of utilizing a device new to the Company, and each took time to review and correct.

The lessons learned and extended lead times led the Company to reevaluate the number and type of voltage regulators required to provide benefits as well as alternative technologies that can be deployed to provide voltage support. The 2021 GMP deployments have reduced the number of voltage regulators within the design and will use microcapacitors to provide voltage and VAR support at feeder extremities and to address voltage unbalances. Engineering for all remaining regulators has been completed in 2021 and will be deployed in 2022.

(b) Capacitors

The capacitor banks were relatively straightforward pieces of equipment to install and there were limited challenges except, as with the regulators, when field commissioning several devices. As with the regulators, the Company discovered several factory-caused communications and wiring discrepancies when field testing the devices. This is often the consequence of utilizing a new system/device, and each took time to review and correct.

The 2021 implementation included installations at a different voltage level than previous deployments and the Company discovered an incompatible sensor that was paired by the factory in the Capacitor kits. The lead times associated with the correct replacement have delayed installation and commissioning into 2022.

(c) Line Sensors

While the selection of the feeder-head monitoring sensor was straightforward, and the Company's process for procurement, installation and commissioning of the devices was performed very efficiently, ongoing maintenance issues with the sensors has caused the Company to reevaluate usage in future deployments. Going forward, the Company plans to utilize relay-based sensors located at the feeder breaker rather than line sensors.

The design, selection and procurement of the end-of-line/grid-edge sensors was challenging. This was primarily due to the lack of industry standardization on this nascent technology that the Company could utilize to guide the selection process. As a result, the procurement process was iterative and time consuming. However, even with the unforeseen delays, the installation of the end-of-line/grid-edge sensors was straight-forward, and the work was completed on schedule within the 2019 GMP plan year.

Over the 2021 GMP plan year, the Company identified manufacturing defects in the end-of-line/grid-edge sensors. These errors caused erroneous voltage reads at the sensor locations. The Company worked with the sensor vendor to design changes to mitigate these issues. All future end-of-line/grid-edge sensors purchased from the vendor will incorporate these design changes.

(d) LTC

Although there were no deployments in the 2020 or 2021 GMP plan year, the lessons learned with the LTC program were similar to the microprocessor relay program, specifically in requiring close coordination between Company departments undertaking these GMP investments. Please see Section III.B. for further discussion around the lessons learned.

The Company took the lessons learned from the 2018 GMP investment year and applied them to the remaining units in 2019. The Company focused specifically on ensuring that it had sufficient time to plan and allocate the correct resources. This program was successful in 2019 and the Company completed all the originally planned investments in 2019, ahead of schedule. The 2021 VVO deployments did not require LTC control upgrades at the selected stations since they had been upgraded previously through other capital projects.

(e) VVO IT

During the procurement process, which started in 2018 and was completed in Q1 2020, the project team found the live demonstrations and reference calls associated with this technology to be quite valuable. The team held detailed reference calls with other utility customers that had procured similar IT platforms and implemented VVO pilots and was able to ask questions about their experience and lessons-learned from their respective VVO pilots and deployments. The Eversource team incorporated that insight into its deployment strategy, both for the field devices and in the contract for the VVO software package.

During the IT system deployment, which took place in 2019 and 2020, the project team faced challenges in implementing the VVO system architecture. One challenge involved having to provide access to the engineering and analytical teams outside of the control room while still meeting the stringent IT security requirements that apply to electric operations infrastructure. This necessitated a significant collaboration between multiple Company departments and a series of architectural modifications, which resulted in a creative solution that successfully balanced the competing requirements. These challenges were further exacerbated in 2020 when, due to the on-going COVID 19 pandemic, the project team (including Company employees as well as contractors and vendors) was restricted to working remotely or in small, socially distanced cohorts. The project team had to re-tool the training, which was intended to be live and in-person, to be recorded and delivered remotely. Additionally, a moratorium on new technology deployments in the control room delayed the training delivery scheduled for Q1 2020 to Q3 2020. Despite the unexpected challenges and delays, the IT implementation was completed and placed in-service and operational in December 2020. The 2021 deployment will be commissioned into the centralized VVO control system in 2022.

Lastly, in a holistic approach to system operations, the project team was able to cross-coordinate with the Company's solar operations team to obtain actual weather data at a solar site in the vicinity of the VVO circuits, which enabled the team to correlate electrical measurements with coincident weather conditions and have better insight into some anomalies observed in the VVO data. This type of collaboration further refines an integrated electric distribution system and increases capabilities and understanding.

(f) Microcapacitors

The Sentient, formerly Varentec, microcapacitors are a new piece of equipment on the Company's distribution system. They were chosen as a cost-effective, straight-forward, and generally non-obtrusive device that will provide localized voltage support on the secondary distribution system.

The Sentient devices utilize a separate operational platform, via the vendor's web portal (GEMS). The web platform is used to commission and visualize the deployment of the microcapacitors and enables data acquisition, remote settings changes, and system performance monitoring. Though this system is meant to help augment the Company's newly commissioned VVO system, the Sentient system was deployed as stand-alone with potential for future integration as the vendors continue to develop their interoperability with new technology. With the addition of microcapacitors to address localized low voltage conditions, fewer voltage regulators are expected to be required for future VVO deployments.

(g) Grid Monitoring Line Sensors

The Company utilized its prior knowledge and experience of installation of the Aclara line sensors when installing the devices (Aclara) for this new investment. The device procurement and field installation are relatively simple and the addition of these devices to the vendor's web portal is a known process.

Although the implementation was a straightforward process, the volume of device installations in 2021 proved to be a challenge due to the incremental resources needed. This was particularly true in the Company's southern region where the original 2021 work plan had been disrupted through a series of different project schedule changes.

Overall, this was a successful investment with limited lessons learned.

22. Description of Benefits Realized as the Result of Implementation

There are immediate benefits to the Company in having visibility and control of additional devices in the field, such as increased voltage monitoring and regulation, as part of the fully commissioned VVO system and the new microcapacitor deployment. Additionally, the increase of the investment types identified in this section has a positive effect on the system automation saturation metric.

Based on preliminary results from ON/OFF testing, the Company has observed consistent reductions in operating voltage in line with expectations when VVO/CVR is enabled and operational. Figure 30 and

Figure 31 show two different visualizations of the voltage effects of the VVO scheme. Figure 30 shows the distribution of voltage measurements at the LTC for both VVO disabled and enabled. It is important to note that not only is the average voltage reduced when VVO is enabled but the voltage also has a larger operating range. This range signifies the dynamic control of VVO and the ability to both reduce voltage but also to accommodate for changing circumstances to ensure reliable customer service.

Figure 30: LTC Voltage Distribution of VVO Disabled and Enabled

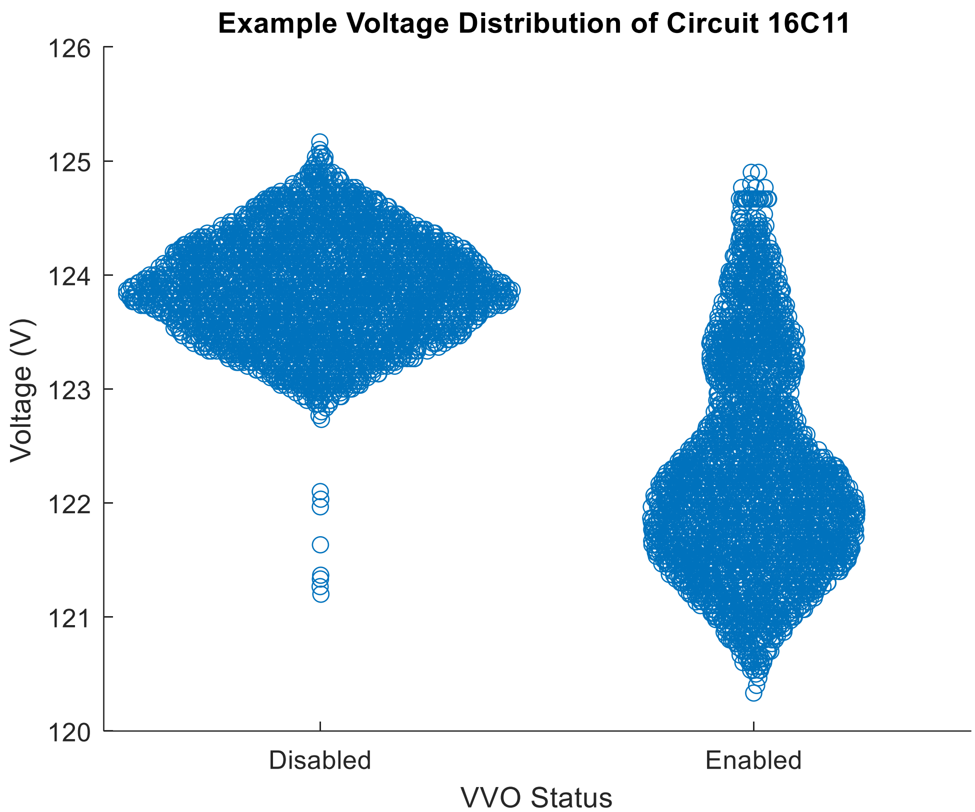
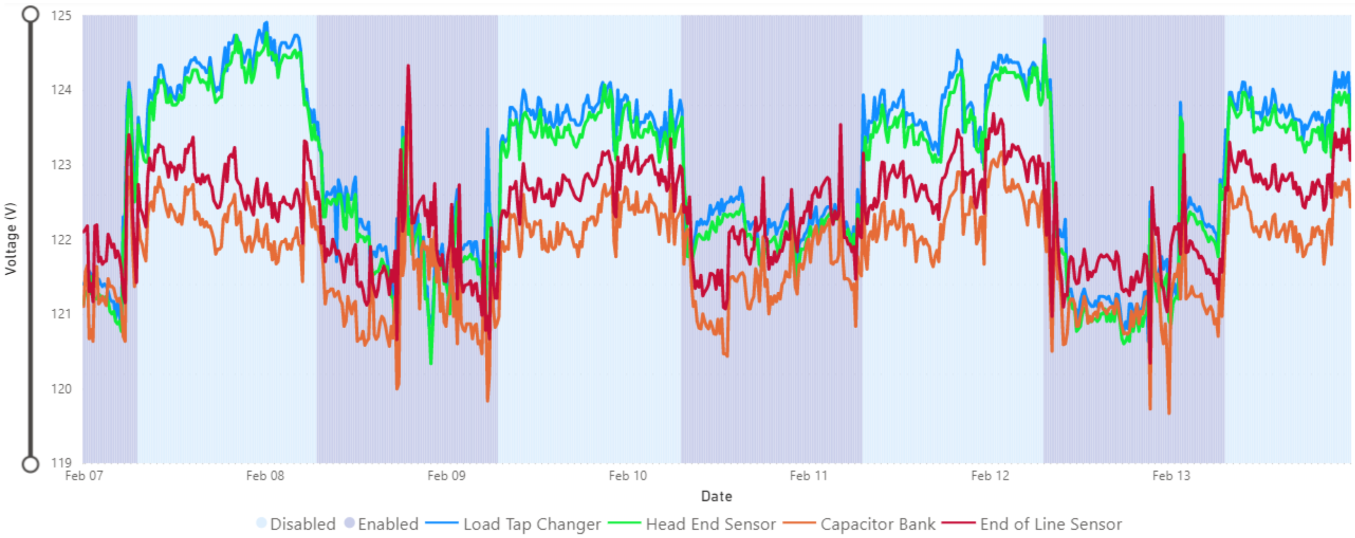


Figure 31 gives a more holistic view of the voltage effect the VVO schema has on a circuit. Each line represents the voltage of a different device on the circuit and the shaded background represents the engagement status of VVO. While VVO is disabled, lighter blue shading, the average voltage is not only higher than VVO enabled voltage but also has a wider spread grouping. The larger range of voltage between devices is a visual representation of the line losses experienced as the measurements move further away from the substation. Having a tighter grouping at a lower average voltage shows VVO's ability to mitigate line losses enabling the opportunity for conservative voltage reductions.

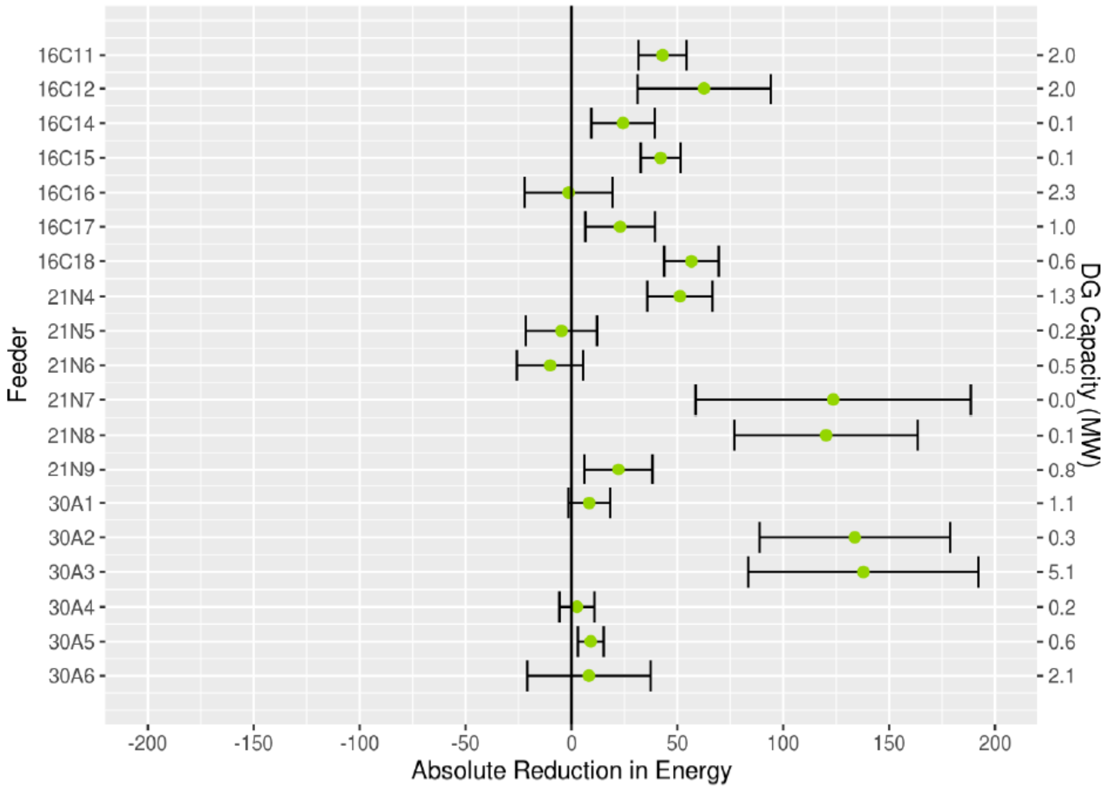
Figure 31 Feeder Voltage Profile with VVO Disabled and Enabled



Preliminary results provided by Guidehouse showed the VVO scheme realized average energy savings of 853 ± 124 MWh, or 0.75 ± 0.11 percent of the attached circuit load, from an average voltage reduction of 1.24 V, resulting in a CVR factor (CVRf) of approximately 0.82, which surpasses with the CVRf of 0.6 that Eversource projected. The preliminary energy savings from VVO is identified for each circuit in

Figure *32*. Following the monitoring and quantification of benefits from preliminary testing, more aggressive voltage reduction settings were implemented, following which consistent voltage reductions of 2-3 percent were achieved on VVO enabled days, including during high heat and load periods in the summer. However, because the increase voltage reduction was implemented in mid-2021 and several equipment issues required maintenance outages on the scheme, ON/OFF testing is continuing to cover the required seasonal diversity. Testing also highlighted some limitations and ongoing maintenance that was required to address equipment failures and devices settings that needed to be updated to keep the scheme operational.

Figure 32 Net Energy Reduction for VVO Feeders Based Off of Preliminary Guidehouse Analysis

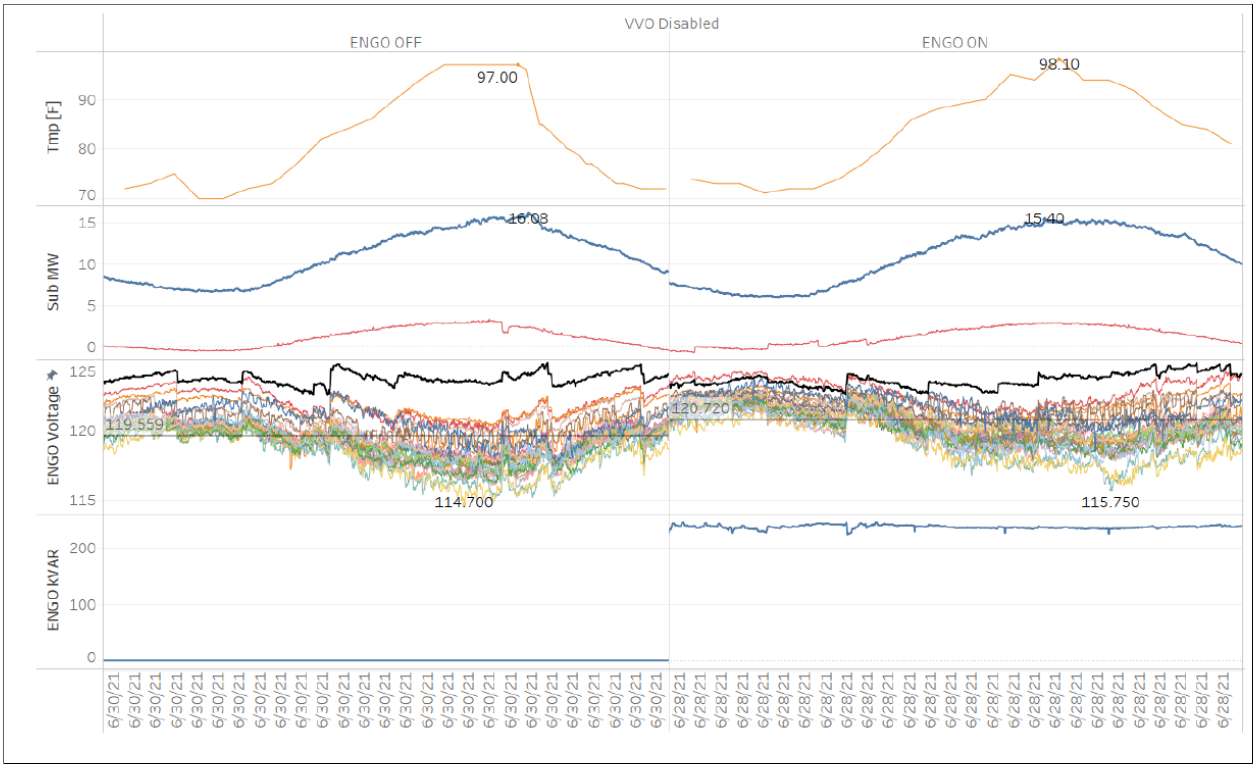


Source: Guidehouse PY2020 VVO Evaluation Report, filed June 30th, 2021

The ENGO microcapacitor deployment is operating as intended to dynamically support secondary voltage in the zones where they are deployed. Results, provided by Sentient, following the 2020/2021 deployment identified a 0.92-1.54 percent voltage boost on average. This voltage boost represents voltage reductions and energy savings from the central VVO system, which amounts to approximately 2,184 MWh or 2.47 percent of the attached circuit load. During the Measurement and Verification Phase, data was collected on two similar high heat days.

Figure *33* shows local ambient air temperature, substation load in megawatts, voltage measured at individual microcapacitors, and the aggregate reactive power injection of microcapacitors, from top to bottom respectively. Measurements such as temperature and substation load are shown to provide context, showing that the two days' worth of data are taken from similar peak load conditions. Despite the high load, the ENGO microcapacitors successfully boosted voltage through kVAR injection.

Figure 33 ENGO Microcapacitor Performance During Peak Loads



The addition of the grid monitoring line sensor program allowed for an increased situational awareness of electrical conditions at key locations within the distribution system. These sensors would allow for the visibility and analysis of historic data at locations such as: 1) DER plants that did not have a recloser installed at the point of interconnection; 2) where there are large step-down transformers; and 3) larger, fused side-tapped circuits. Because the Company had already been using the Aclara line sensors, and the accompanying web portal for data acquisition, the visibility benefits of the grid monitoring line sensors were immediately realized at deployment.

For further analysis, refer to "Massachusetts Grid Modernization Program Year 2021 Evaluation Report – Volt Var Optimization" which will be provided by Guidehouse (formerly Navigant Consulting) on June 1, 2022.

23. Description of Capability Improvement by Capability/Status Category

Eversource targeted the deployment of VVO in a limited geographic region (WMA) that consisted of substations and circuits under the jurisdiction of a single control room. The circuits in the target region offered a diverse mix of load and distributed generation ("DG") penetration, which is expected to provide a comprehensive understanding of the impact of VVO across a broad range of circuit types. Within the target region, Eversource picked locations for the pole-top devices based on a combination of load flow analyses, engineering judgment, wireless communication coverage, and any local siting concerns.

The strategy for deployment was focused on maximizing the Company's ability to understand and quantify the benefits from VVO while minimizing the number disruptions to control room and field personnel impacted by the deployment. The lessons learned from the 2018-2020 deployments were incorporated into the 2021/2022 expansions in WMA as well for identifying additional stations in EMA to deploy VVO.

The metering capabilities of the VVO field devices at the stations and along the feeder, which are timestamped and archived by the VVO control software, delivers a level of visibility and monitoring into the distribution system that was previously unavailable. In addition to understanding and quantifying the benefits of VVO, the Company is using this data to gain additional insight into energy use patterns along the feeder and to augment and validate planning and forecasting models.

24. Key Milestones

(a) VVO Line Devices

- Developed and implemented a revised design standard for the largest of three types of regulators – implementation of the regulators under the new standard is 100% complete for the original VVO plan (2018-2020 GMP).

(b) VVO IT

- Fully commissioned the original VVO IT system in late 2020.

(c) Additional Investments

- Successfully added and executed a microcapacitor program in 2020.
- Successfully added and executed a grid monitoring line sensor program in 2020.

D. Advanced Distribution Management System ("ADMS")

1. Performance on Implementation/Deployment

Refer to Figure 34 below for the Company's 2018-2021 implementation spending summary for the ADMS GMP Investments. There is no unit deployment summary for this investment category as all the investments are in technologies that are not unitized.

Figure 34: 2018-2021 ADMS Implementation Capital Spending Summary ($)

Investment Category	Preauthorized Device Type	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2018-2021 Actual	2018-2021 Projection*	% Difference
Advanced Distribution Management System (ADMS)	Advanced Load Flow	-	2,775,876	6,033,013	153,907	8,962,796	8,808,889	2%
	GIS Survey (Expense)	-	-	-		-	-	N/A
	Dist. Management System	-	-	-	1,596,259	1,596,259	8,000,001	-80%
	Forecasting Tool	-	-	-	1,843,343	1,843,343	3,246,003	-43%
	Synergi Upgrades	-	-	-	942,445	942,445	767,003	23%
	PI Asset Framework	-	-	-	1,076,564	1,076,564	986,498	9%

(a) DMS

The DMS project commenced in September 2021. The initial effort in 2021 was to build out a detailed project plan that provided further details on the summary tasks that the Company had already established. This effort took the overall plan and broke it up into six tracks: Deployment, Infrastructure, Interfaces, Modeling, Testing, and Training. Within these tracks hundreds of tasks were identified and documented for scope, duration, dependencies, and responsibility. The necessary project resources have also been identified and onboarded to work the project task list.

With the initial project planning completed by November 2021, the project team was able to complete the following project tasks:

- Designed and specified the IT environment for purchasing hardware and build of the development environment.
- Identified the database changes required to be made to the existing SCADA system to support the integration with DMS.
- Collaborated with vendor to establish a development environment that enables both teams to do initial build to prove out design

The DMS project plan currently estimates final go-live for all control centers in Massachusetts for Q4, 2023.

(b) Synergi Upgrades

The Company successfully completed the Synergi Upgrades project in 2021. This project included enhancements to the processes outside of Synergi and automating analysis within Synergi to produce improved hosting capacity maps. The project team first built scripts within Synergi to process the hosting capacity calculation across all the MA feeders. The calculation was also configured to solve for each line segment of a circuit. Finally, an automated process to take the Synergi results and post to the Company's external map was designed and built to enable a monthly refresh. The hosting capacity maps are now utilizing this new automation.

(c) Advanced Forecasting

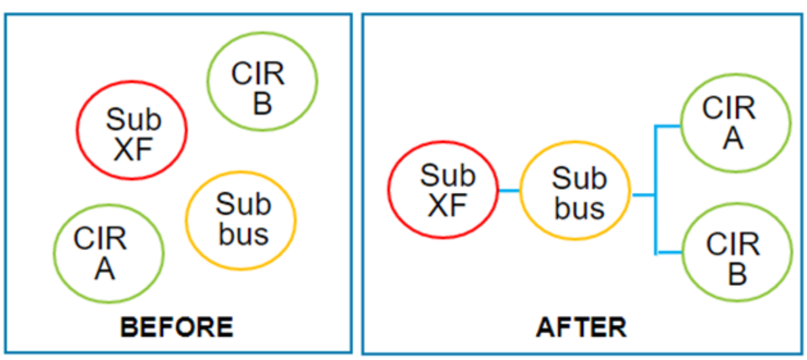
The Advanced Forecasting project commenced in August 2021. Initially, a detailed project plan was built out to provide the details for tasks and resource allocation. After kickoff, the Company was able to complete the Design Phase of the project. This included data mapping, interface requirements, IT environment requirements, and software configuration. Next, the project built out the solution by providing historical data, building network rules, and configure the product to the Company's use cases. This included going through scenario building for different adoption rates of DER and EV's. The project was not able to complete all its testing and final implementation in 2021. The expected completion is Q2 2022.

(d) PI Asset Framework

The PI Asset Framework project commenced in August 2021. The project plan was established to include design, build, test, and go-live phases. The Company was able to complete the design phase where it defined the electrical hierarchy and structure of the data to be created within the PI Asset Framework system. The Company did not commence the build or subsequent phases in 2021. The expected completion of this project is Q2 2022.

Prior to the initiation of the PI Asset Framework Project, the Company identified a need to organize information in the PI system. All PI tags were stored at a single level, disregarding the element class. PI tags also did not have a conventional naming system, causing increased difficulty for new users to access the data. A visualization of the unstructured data can be seen in the "Before" section Figure 35, below. With the electrical hierarchy and structure of data, users will be able to quickly identify location of data. An example of the structured data is shown in the "After" section of Figure 35.

Figure 35 Visualization of Data Organization Before and After the PI Asset Framework Project



(e) Advanced Load Flow

This GMP includes the implementation of Advanced Load Flow ("ALF") software to create detailed computer models of the Company's distribution system for the purpose of long-range engineering analysis. In parallel, the data sources critical to the accuracy of the models will be assessed and enhanced as necessary to leverage the advanced functionality of the software. This enhancement of model data sources will also be critical to the operation of other functions, including VVO and the ADMS. During the implementation of ALF, the Company:

- Completed implementation of a consolidated Central Engineering Database ("CED") to assemble and manage non-GIS data required for accurate models.

- Completed implementation of the automated process for building Synergi models from the separate GIS environments for EMA and WMA, along with automated integration to the CED.

- Refined and implemented a new algorithm for automatic estimates of transformer loads, based on customer billing/usage data, and applying a correction factor to account for customer DG impact on usage.

- Performed significant data cleanup in GIS for major distribution equipment and conductors. Priority was placed on those elements most impactful to model performance.

- Established an automated process for building the Boston underground secondary mesh network from GIS.

- Provided basic and advanced training to impacted engineering groups to enable end-user acceptance.

(f) GIS Verification

With the deployment of various information IT/OT projects, such as ALF and distribution management it was important that the Company perform a survey of the overhead distribution system in order to ensure connectivity models are true and accurate. The original 2018-2020 GMP included the survey of all of the Company's easter region. This work was completed in late 2019 and the records were uploaded to the GIS system. As part of the supplemental 2021 GMP, the Company expanded this work into the western region.

For each region, east and west, the survey work was outsourced, and the Company held a competitive solicitation to a group of survey vendors. After award, the process included a pilot/test location of survey data and information upload, so to ensure all relevant data was being collected and that the batching and quality of data was retained when being uploaded to the Company's GIS.

At the end of 2021, the project in the western region was 80 percent complete. As of late February 2022, the entire project has been completed and closed out. These two projects validated the connectivity of customers in the Company's entire Massachusetts overhead distribution system.

25. Lessons Learned/Challenges and Successes

(a) DMS

The DMS relies heavily on the data that supports its model. One key data source is the Company's SCADA system. The Company identified early on that the more consistent the SCADA system is modeled across device installations, the easier the integration to DMS will be to build out. The Company will need to make some minor changes to its SCADA system in order to enable this integration. This is also an area of success, where the Company has leveraged its internal knowledge gained in other jurisdictions to the benefit of this Massachusetts project. This issue was identified early on, and a plan has been built to address it.

Another major challenge is the coordination between the DMS project and the Company's GIS Consolidation project. Through the consolidation effort, the Company is changing the data model it uses for its GIS system. This change has downstream impacts to the DMS as a consumer of the data. The DMS project has worked very closely to manage schedule impacts from the GIS project. This risk will continue; however, the Company is positioned well to mitigate the risk to the DMS project.

(b) Synergi Upgrades

A consistent lesson learned that was again realized within the Synergi Upgrades project is that the solution is heavily dependent on the source data. For this project, the data needed to run an automatic process on all feeders in Massachusetts is very large and has different sources. The Company built tools and approaches to evaluate this large set of data to find anomalies. Once anomalies were found, the data was corrected in the source data and then reflected in the process output. This iterative approach will be required for the ongoing maintenance of the system.

(c) Advanced Forecasting

The Advanced Forecasting software is very flexible which allows for many DER adoption scenarios to be built with different assumptions for multiple variables. The Company has identified how to build out the basic scenarios and learned how to configure the tool which will allow for the addition of more complex scenarios in the future. This will be extremely valuable for system planning to allow for more "what-if" scenarios that can be assessed. This will further enhance the Company's distribution planning process.

(d) PI Asset Framework

For the PI Asset Framework project, the Company identified that consistent naming of data within its historical data is critical to being able to process. For example, the measurement of MW and MVAR for a substation breaker was found to be labeled with multiple unique names. The project team had to investigate each unique instance to understand from what piece of equipment in the field was the data coming from and then could accurately map it to the correct asset in the new framework. Without consistency, the Company found many unique instances. Going forward, with the framework in place, this data can be quickly accessed and utilized for analysis.

(e) ALF

In 2020, the Company was focused on completing the implementation of the ALF system, which includes the Synergi software tool rollout, the automated Synergi model build process, and a Central Engineering Database ("CED") tool which provides certain detailed engineering data for the models. The implementation process involved multiple iterations of model builds in a test environment. The synchronizing of "snapshots" of multiple live databases in this test environment proved very challenging, as the Company detected a number of model errors due to "stale" data in one snapshot or another.

Data cleanup (beyond the overhead GIS verification work completed in 2019) also proved to be more significant and time consuming than planned. Most of the work was completed with desktop analysis, using Company maps along with tools like Google or Bing Streetview. Several locations still need to be examined in greater detail, and possibly require field verification as the Company continues to refine the models. At this stage, models typically require some manual adjustments and corrections prior to running any automated processes

(f) GIS Verification

The GIS Verification projects were generally successful due to the efforts that were completed during both solicitation and during project start up. The use of the "pilot/test" area proved to be valuable to ensure that the data collection process was complete and that they data input to the Company's system, was accurate.

In the western region, the apparent challenges of COVID had an effect on the ability to obtain and retain contracted field personnel for data collection. This caused the project timeline to extend into early 2022.

26. Description of Benefits Realized as the Result of Implementation

(a) DMS

The DMS has not been implemented yet. The expected in-service date is Q4, 2023. The Company has not identified any variances between planned benefits and what will be delivered.

(b) Synergi Upgrades

With the completion of the Synergi Upgrades project, the Company has realized the following benefits:

- Improved experience for DER developers to site potential projects
- Improved system view for internal engineering group to assess capability to accommodate additional DER, or to determine where to site other DER assets
- This automated process can be leveraged in other parts of the Eversource system, as well as to produce results other than just hosting capacity (for example, system loading, power factor, and reliability)

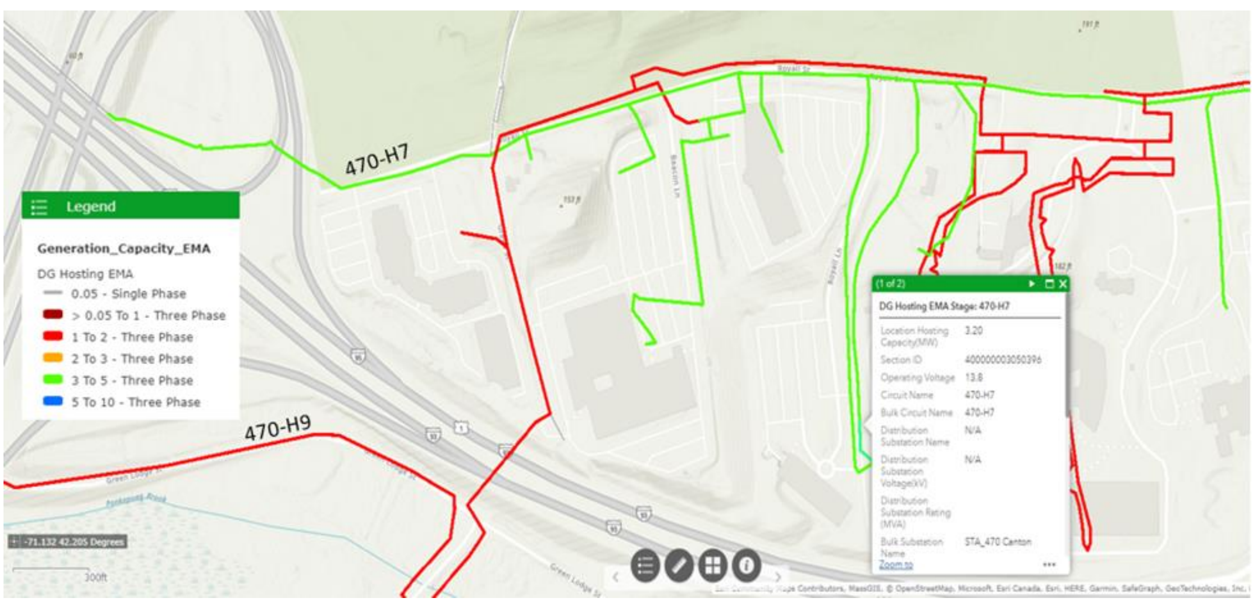
In addition to these benefits, the Company gained more experience with building and executing calculations across its entire distribution network that will help expand its capabilities in other areas.

Below are two figures that show the before and after hosting capacity maps as a result of this investment.

<u>Hosting Capacity Map Before Synergi Implementation:</u>

Prior to the deployment of Synergi, the Company's planning team would manually pull together static DER data for all circuits within the operating state. This process required extensive time and resources to deliver just one value of hosting capacity for an entire circuit. Figure 36 shows a hosting capacity of 3-5MW for circuit 470-H7 and a hosting capacity of 1-2MW for circuit 470-H9. While this is the capacity for the entire circuit, a segment level distinction may reveal a more limited capacity for specific segments. Lacking this vital information may result in unexpected delays or additional costs associated with a specific project as a result of a more in-depth DG impact study. The data had to be manually refreshed monthly and the company was unable to provide customers with the level of detail desired.

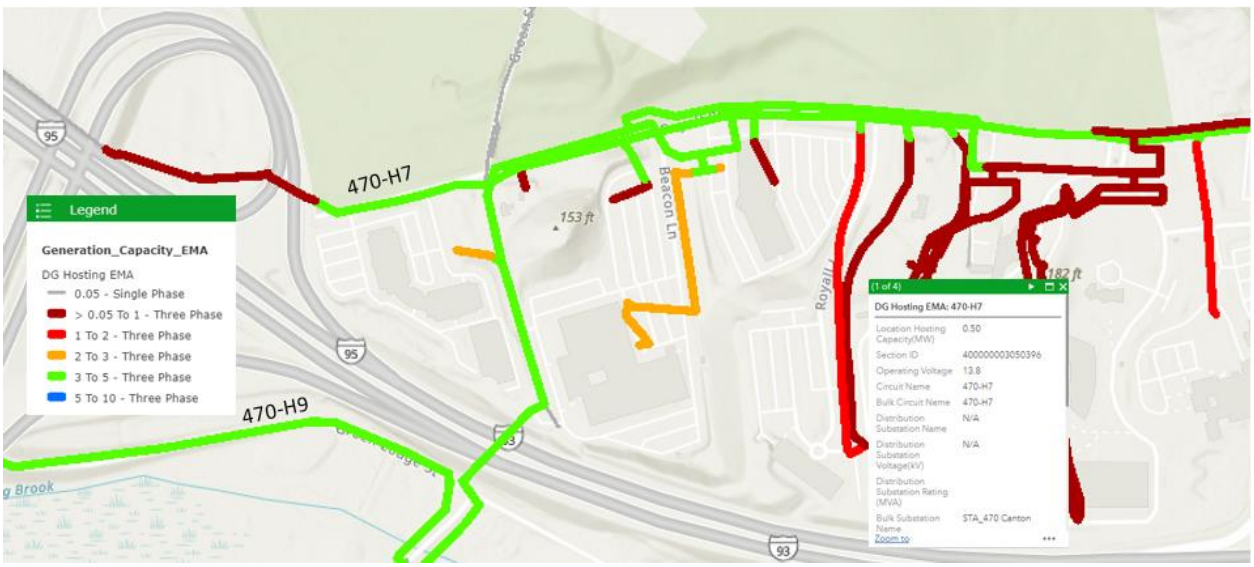
Figure 36 Hosting Capacity Map 2021 (Before Synergi Implementation)



Hosting Capacity Map After Synergi Implementation:

After the implementation of Synergi, the Company was able to integrate with existing systems such as, CED and Designated Engineering Representative Tracking System ("DERTS") to develop automated hosting capacity maps with the desired level of detail which is automatically refreshed monthly. Figure 37 shows how the 3-5MW and 1-2MW of hosting capacity is distributed to the segments of circuits 470-H7 and 470-H9 respectively. With Synergi's implementation, fewer resources are required to validate and maintain the maps, with more confidence that the data is as current and accurate as possible. The new process holds the main benefit of the availability to show hosting capacity for every individual segment of a circuit. Providing future and existing applicants with this level of visibility is essential in gauging the time or costs constraints that may be associated with their application.

Figure 37 Hosting Capacity Map 2022 (After Synergi Implementation)



(c) Advanced Forecasting

The Advanced Forecasting project has not been placed in service. The expected in-service date is Q2 2022. The Company has not identified any variances between planned benefits and what will be delivered. Expected benefits include the following:

- By providing locational adoption rate forecasts of specific technologies, Eversource will be able to inform its long-term plan in a more detailed manner;
- Better identification of areas on the distribution grid that risk violating system planning criteria;
- More discrete adjustment of capital plan to account for DER technologies;
- Bottoms up methodology to augment current process to break down corporate level forecasts by station;

- Probabilistic methods provide detail on likelihood of various forecast scenarios which help to mitigate risk for system investments;
- Early identification of system constraints due to policy changes; and
- Support for regulatory and policy analysis based on adoption rate forecasts.

(d) PI Asset Framework

The PI Asset Framework project has not been placed in service. The expected in-service date is Q2 2022. The Company has not identified any variances between planned benefits and what will be delivered. Expected benefits include:

- Improved ability to process large data sets to provide historical measurements;
- Improved accessibility to data within the Company's historical database; and
- Reducing time to manipulate data to meet different analytics needs.

(e) ALF

There was no deviation between planned and actual benefits of the ALF project. Benefits realized as part of the ALF project include:

- Improved ability to optimize capital asset deployment and system reconfiguration;
- Better contingency scenario planning, including within the secondary network;
- Increased accuracy of GIS and other related data, lowering the cost and timeline to achieve the level of data accuracy required to support a DMS load flow;
- Reduced cost and time to perform impact studies for customers applying to interconnect DER to the Company's distribution system;
- Platform to perform more advanced analysis with automated logic, including automated hosting capacity analysis;
- Faster and more accurate analysis of new customer connections to the network, including spot network configuration analysis; and
- Root cause analysis of failures.

The following section provides detail on the Company's prior practice before the ALF project and the post-project functionality that was enabled.

<u>Prior Practice Before the ALF Project</u>

Before the ALF project was implemented, the Company used two different load flow software packages. In EMA, some areas used a software called Cooper CymDist and other areas, including the downtown Boston underground network, relied on manual spreadsheet-based analysis. In WMA, engineers used a dated version of the Synergi software with limited automation. Each region used a separate process, which were not standardized across the Company's territory.

In EMA, the prior practice to create load flow models was a protracted procedure. The planning engineers or technicians had to manually import the circuits, bring in service transformer loads from the transformer load management system, bring in primary metered large customer loads from another system, bring in feeder loads from PI, check connectivity, clean up connectivity where it was lacking, and allocate the loads in the modeled circuits and scale them so the models were tuned to represent actual field conditions. Even at the maximum extent of deployment, large portions of the EMA system were not modeled in CymDist. The practice was unsustainable because the models that took extensive time and patience to prepare quickly became outdated as changes occurred in the field. Substantial time was also used to train new employees on the procedure.

In WMA, the prior practice to create load flow models relied on an older version of the Synergi software from the mid-2000s. While the process was not as painstakingly manual as the EMA region due to more automation, certain parts of the process still required significant manual intervention that could potentially translate into days of work to model larger circuits. The process also relied on more estimations, which resulted in less accurate results than desired.

Current Practice After ALF Project

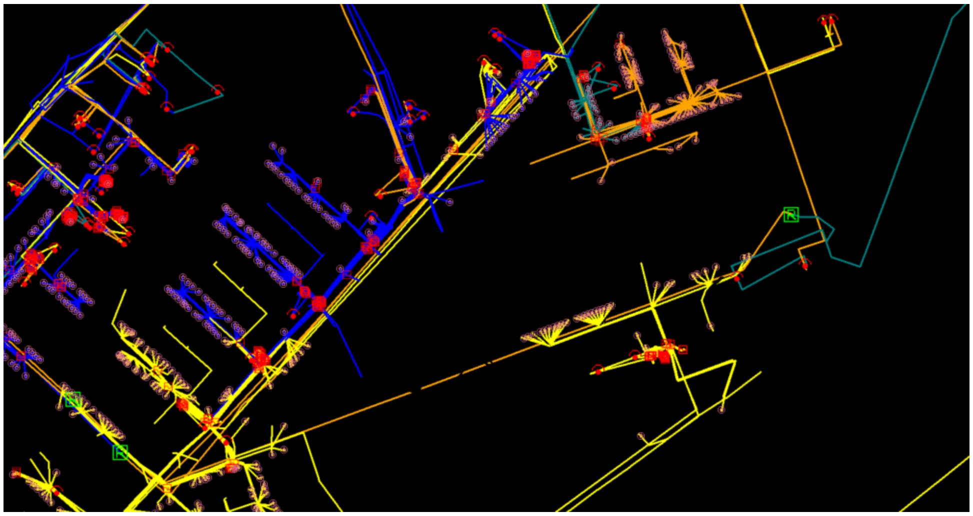
As a result of the Grid Modernization ALF project, the Company now uses one load flow software and a standardized practice to run load flow models across the Massachusetts territory. The process of load flow models has been substantially simplified. Because Synergi is directly driven off of the GIS, the transformer load management system, and primary metered loads, the majority of the hand-required maintenance has gone away. Load flow cases are refreshed automatically and changes in GIS can be reflected automatically.

Detailed Synergi models have also been created for the DG “Cluster” analyses that are being performed for various EMA and WMA substations consistent with the directives issued in D.P.U. 20-75. The new process integrates with the Company’s DER database to automatically refresh the models with both in queue and installed generation on a weekly basis. This new process allows the Company to release monthly hosting capacity maps at any desired frequency, while also improving any delays that applicants may have seen associated with the DG impact study in the past. These could not have been done with the manual processes and prior software.

With some additional external data input, the Synergi models are also capable of full 8760-hour analysis if the data is available, including creation of solar PV generation patterns based on solar irradiance data.

Figure 38, below, shows a representation of a load flow model of an underground network, which is used by distribution and system planning engineers to complete network load flow and N-1 contingency analysis. Prior to the ALF project implementation, the company was unable to model the secondary network in load flow software and relied primarily on spreadsheet-based analysis tools.

Figure 38 Portion of Representative Load Flow of Underground Network in Synergi



(f) GIS Verification

- The verification of data will directly contribute to the various existing and new electric distribution system GMP platforms.
- Improved accuracy of the as-constructed distribution model.
- Greater accuracy in customer outage communications.

27. Description of Capability Improvement by Capability/Status Category

(a) DMS

The Company has commenced its implementation of the DMS for its control centers with the expected delivery of the following capabilities by Q4 2023:

- System-wide three-phase unbalanced power flow calculation in real time;
- System-wide fault location, isolation, system restoration ("FLISR") capability;
- Model based VVO application within DMS;
- Electronic switch order management;
- A study mode that allows a user to evaluate a system condition prior to taking action; and
- Distribution operator training simulators to enhance the training program for operators.

(b) Synergi Upgrades

The Synergi Upgrades project enabled the Company to perform segment level hosting capacity calculations in a batch process for all feeders in Massachusetts. This result is also then processed to be shared publicly via the Company's existing Hosting Capacity Maps.

(c) Advanced Forecasting

Although the Advanced Forecasting project is not yet implemented, it is expected to enable the Company to better address the challenges posed by inherent uncertainties in DER adoption and utilization, including the localized impacts of DER interconnections. This new tool is expected to enhance the Company's capabilities to distinguish new DER assets from traditional customer load in its forecasting process. Additionally, using a more probabilistic approach in forecasting the adoption of various DER assets in the system model will enable more detailed decision making with respect to long term system planning activities. More specifically, this project will help transition our forecasting capability from a top-down approach to a more detailed bottoms up tool. In doing so, more sophisticated manual analysis can be performed to better inform our planning process

(d) PI Asset Framework

The PI Asset Framework will make the Company's data set more accessible and manageable. This improves the largely manual effort that engineering groups spend when working with historical operational data today. Of equal importance, making the PI data structurally accessible and available outside of the PI system opens the data set to many users within the Company that either were not aware of it or unfamiliar with the process for accessing it. This will make verification activity more efficient in the future.

(e) ALF

With the completed work in Advanced Load Flow, the Company has significantly improved its distribution modeling capability. An automated model build process from the most recent GIS configuration, as well as other up to date, active data sources, improves the Company's ability to perform system planning studies across the entire distribution system, including the downtown Boston underground secondary network. Engineers will spend less time assembling the models and more time assessing results from future changes and additions. This model build process will also be a key enabler of future automated analyses involving large numbers of circuits

(f) GIS Verification

The verification of electrical connectivity in the field was an important step to ensure correct and accurate data are included in the Company's GIS system. The GIS system feeds other operations software solutions and will be an integral part of the DMS. Verifying the field connections provides a high level of confidence to allow algorithmic solutions to provide appropriate results.

28. Key Milestones

(a) DMS

- Project Mobilization Complete (Q3- 2021)
- Design Started – Planned Completion Q3-2022
- Build Started – Planned Completion Q1-2023
- Testing – Not Started - Planned Completion Q3-2023
- Go-Live Planned for Q4-2023

(b) Synergi Upgrades

- Project Mobilization Complete Q3- 2021
- Design Complete Q3-2021
- Build Complete Q4-2021
- Testing Complete Q4-2021
- Go-Live Complete Q4-2021

(c) Advanced Forecasting

- Project Mobilization Complete Q3- 2021
- Design Complete Q3-2021
- Build Complete Q4-2021
- Testing Started – Planned Completion Q1-2022
- Go-Live Planned Completion Q2-2022

(d) PI Asset Framework

- Project Mobilization Complete Q3- 2021
- Design Complete Q4-2021
- Build Complete Q1-2022
- Testing Started – Planned Completion Q2-2022
- Go-Live Planned Completion Q2-2022

(e) ALF

The ALF program represents a major improvement from prior load flow capability for Eversource, including new automation of model builds and a new software product for the EMA portion of the Company's service territory. The following milestones have all been completed in the indicated timeframes:

- Phase 1:
  - Mobilization and Design Complete (Q3-2019)
  - Build Complete (Q4-2019)

- Testing Complete (Q4-2019)
- Phase 1 Commissioning (Q4-2019)

▪ Phase 2:
  - ALF Automation design Complete (Q2-2020)
  - ALF Automation build Complete (Q4-2020)
  - Testing Complete (Q4-2020)
  - Phase 2 Commissioning (Q4-2020)

(f) GIS Verification

Eastern Massachusetts:

- Project commenced: (Q3-2018)
- Project completed: (Q4-2019)

Western Massachusetts:

- Project commenced: (Q4-2020)
- Project 80 percent complete: (Q4-2021)
- Project completed: (Q1-2022)

E. Communications

1. Performance on Implementation/Deployment

Refer to Figure 39 and Figure 40 below for the Company's 2018-2021 implementation unit and spending summaries for the Communications GMP Investments.

Figure 39: 2018-2021 Communications Implementation Unit Summary (# of Units)

Investment Category	Preauthorized Device Type	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2018-2021 Actual	2018-2021 Projection*	% Difference
Communications	Numbers of Nodes	0	4	4	2	10	14	-29%
	Miles of Fiber	0	0	0	2	2	0	N/A

Figure 40: 2018-2021 Communications Implementation Capital Spending Summary ($)

Investment Category	Preauthorized Device Type	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2018-2021 Actual	2018-2021 Projection*	% Difference
Communications	Numbers of Nodes	-	522,256	1,105,885	778,560	2,406,701	5,734,556	-58%
	Miles of Fiber	-	309,896	255,618	581,155	1,146,668	1,565,513	-27%

(a) All-Dielectric Self-Supporting ("ADSS") Miles of Fiber

The Company originally committed to deploying 250 miles of fiber optics as part of the 2018-2020 GMP and a very small subset of fiber deployment at five substations as part of the supplemental 2021 GMP deployment. However, in 2019, after further developing and refined the scope and design of the fiber optic deployment, the Company found that the costs were significantly higher than expected, to the point that it was determined the program was not prudent to execute. Except for a small subset of investments from the 2018-2020 GMP, which were very short installations to substations 318, 23, 60, 52 and master radio base station at Bear Hill, in 2019, the ADSS Miles of Fiber program was eliminated from the GMP and funds were redeployed to other investments. The minor fiber optic deployments that were completed were completed in support of other GMP investments at substations 318, 23, 60 and the Bear Hill base radio station (all completed), and substation 52, which is expected to complete in Q2 2022. For reference:

- Substations 23, 60 and 52 were all 4kV substations which also received 4kV circuit breaker SCADA upgrades.
- Substation 318 was expected to be the next substation to receive 4kV auto-restoration loop upgrades.[4]
- The Bear Hill base radio station was an existing radio station to which fiber optics were added for back-haul capability.

For the supplemental 2021 GMP, the Company intended to install a short length of fiber optics at substation 36 and make final fiber optic terminations at four substations in the western region. The installation at substation 36 was supposed to be completed in 2021 but had delays during the engineering and design phases after reviewing the underground conditions. The fiber at substation 36 is planned into the 2022 work plan and is expected to be completed in Q2 2022. The four substations in the western region, which were to have final terminations completed in 2021, will not be completed as part of the GMP. After engineering review, it was determined that there was not sufficiently adequate equipment to terminate the fiber optics, which would allow for a substantive benefit. Therefore, the Company elected not to complete these installations.

The Company's original total capital costs were estimated at $16M for the 2018-2020 GMP and $1.5M for the supplemental 2021 GMP. As discussed above, the majority of the fiber optic budget was redeployed to other investments. The actual total capital costs for the deployment of fiber to three substations and one master radio site (less than 2 miles of fiber), and inclusive of the carry over for two more substations (less than 1 miles), is $1.5M.

(b) D-200 Upgrades

During the initial filing stages for the 2018-2020 GMP the upgrade of the Company's D-200s was not specifically included in the plan. The D-200s are the data concentrator devices that sit adjacent to the Company's SCADA front end processors, that allow various field data (via radio, cellular, or fiber optics) to be aggregated and combined before being transmitted to the SCADA and/or PI historian systems.

[4] See Section III.B.1.c) for final disposition of the 4kV auto-restoration loop program.

Due to the large volume of GMP devices that were deployed in the field, the need to upgrade the Company's D-200s to support this additional, incoming data was identified. The D-200 system is a General Electric ("GE") product that is no longer supported. Therefore, the Company chose to install upgraded devices, specifically the GE D-20MX devices. These devices were installed at the Company's Massachusetts Avenue and Plymouth service centers, which are also the locations of the multi-point SCADA system.

The work was completed early in the 2018-2021 GMP term and immediately provided benefits by ensuring there were sufficient capabilities to handle new data transmissions. Though not a "node" as defined as a radio base station, the Company treated the deployment of the two D-20MX installations as one "unit" within the "nodes" investment type. This was mainly due to the funding for the D-20MXs coming from the "nodes" investment type.

(c) Nodes

The Company originally committed to deploy 10 nodes (also known as master radio base stations) as part of the 2018-2020 GMP and four nodes as part of the supplemental 2021 GMP deployment. The Company's implementation of the node program was short of its 14-unit goal by four units. This was primarily due to the deployment of a new 450MHz frequency in the eastern region. The 450MHz frequency will be a new addition to the eastern region. Its deployment is expected to provide higher strength penetration of radio signals to areas which were previously challenged with the higher 900MHz frequency. As part of the deployment of this new frequency, there was an unforeseen condition with the hardware/software integration at the Company's front end processor of the relatively new SCADA system. The trouble shooting of this system pushed the commissioning of these remaining devices into 2022. As of this report, the issues encountered have been resolved and the four new nodes are expected to be operational in early Q2 2022. The Company is continuing on with the nodes deployment and by Q2 of 2022, it is expected that 16 nodes will be commissioned, which is two nodes in excess of the 14-node commitment. The two additional locations were due to sites that were originally passed over for construction feasibility but then brought back into the plan following further analysis. Because the communications infrastructure is vitally important to the GMP, the Company found it prudent to include these locations. It is important to note that the Company grouped the D-200 upgraded at the north and south dispatch centers into the node category and treated both locations as one total node. This was to ensure that the Company's front end processors to SCADA could accept and handle all of the newly commissioned GMP devices in the field.

For clarity, the following is the list of node locations:

Eastern Region:

- D-200 Upgrades in the north and south region (in-service)
- Falmouth Bulk Substation 900 MHz (in-service)

- West Pond Substation – 900 MHz (in-service)
- Prudential Center – 900 MHz (in-service)
- Duxbury Substation – 900 MHz (in-service)
- Martha's Vineyard Service Center – 900 MHz (in-service)
- Shoot Flying Hill – 900 MHz (in-service)
- Bear Hill – 450 MHz (Q2, 2022)
- Nobscott – 450 MHz (Q2, 2022)
- Shoot Flying Hill – 450 MHz (Q2, 2022)
- Prudential Center – 450 MHz (Q2, 2022)
- Southborough Service Center – 450 MHz (Q2, 2022)

Western Region:

- Pocumtuck – 450 MHz (in-service)
- Pelham – 450 MHz (in-service)
- Mt Tom – 900 MHz (in-service)
- East Springfield Service Center – 900 MHz (Q2, 2022)
- East Springfield Service Center – 450 MHz (Q2, 2022)

A sampling of the coverage increases for the eastern region nodes that have and will be installed as part of the GMP can be found below:

Figure 41 Prudential Center – New Radio Master Installation Coverage Before (450MHz before and after)

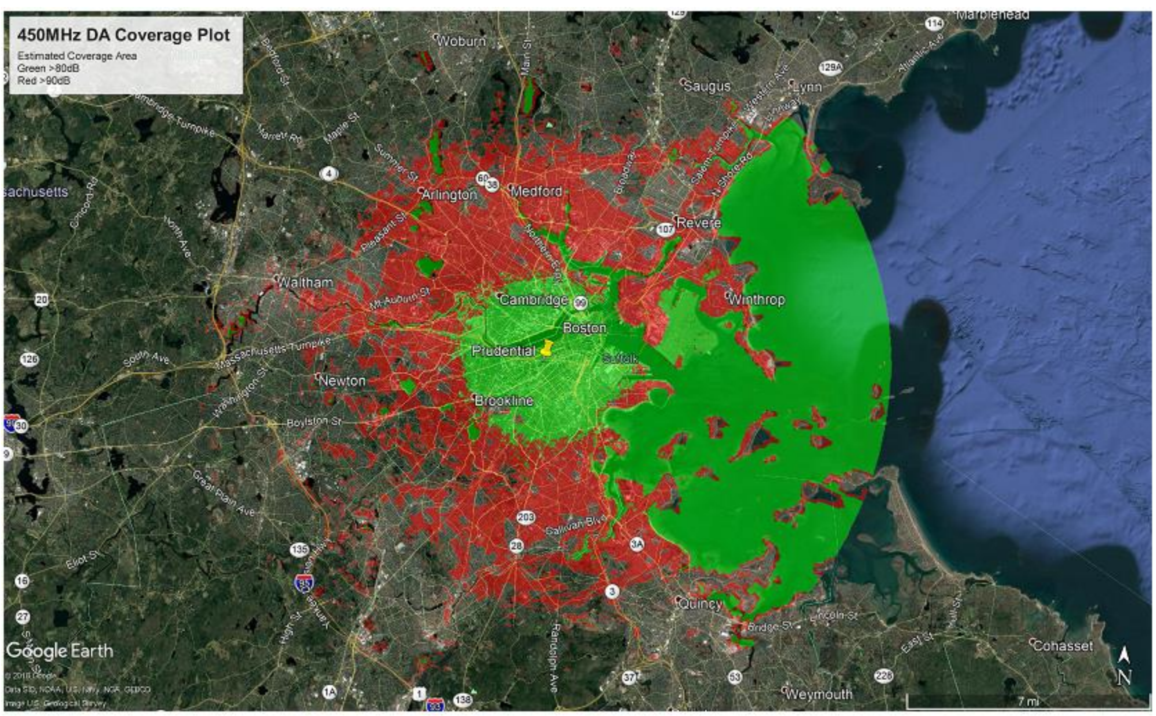
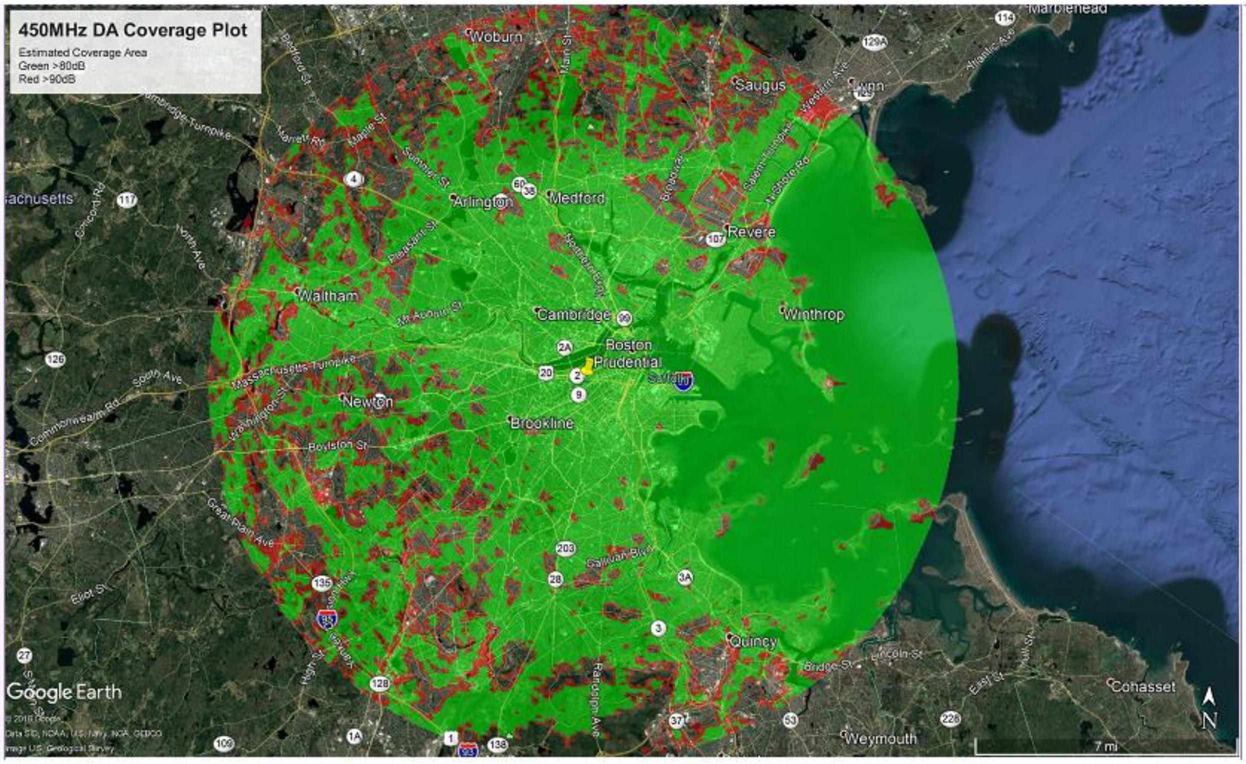


Figure 42 Prudential Center – New Radio Master Installation Coverage After (450MHz before and after)



The Prudential Center was a new radio Master installation and is one of the best performing DA Master sites in the Company's North region providing coverage for remote radios in the Metro Boston area. It was beginning to be oversubscribed due to the number of remote units programmed to it. The new Master radio added under the GMP in 2019 allowed the Company to supplement the existing Master radio, pick up any new DA remotes and avoid the overloading issue. It also provided additional redundancy in the radio network, allowing for the distribution of the remote radios across two Masters, thereby eliminating one as a single point of failure.

Figure 43 Shoot Flying Hill – New Master Radio Before (Before and After Coverage)

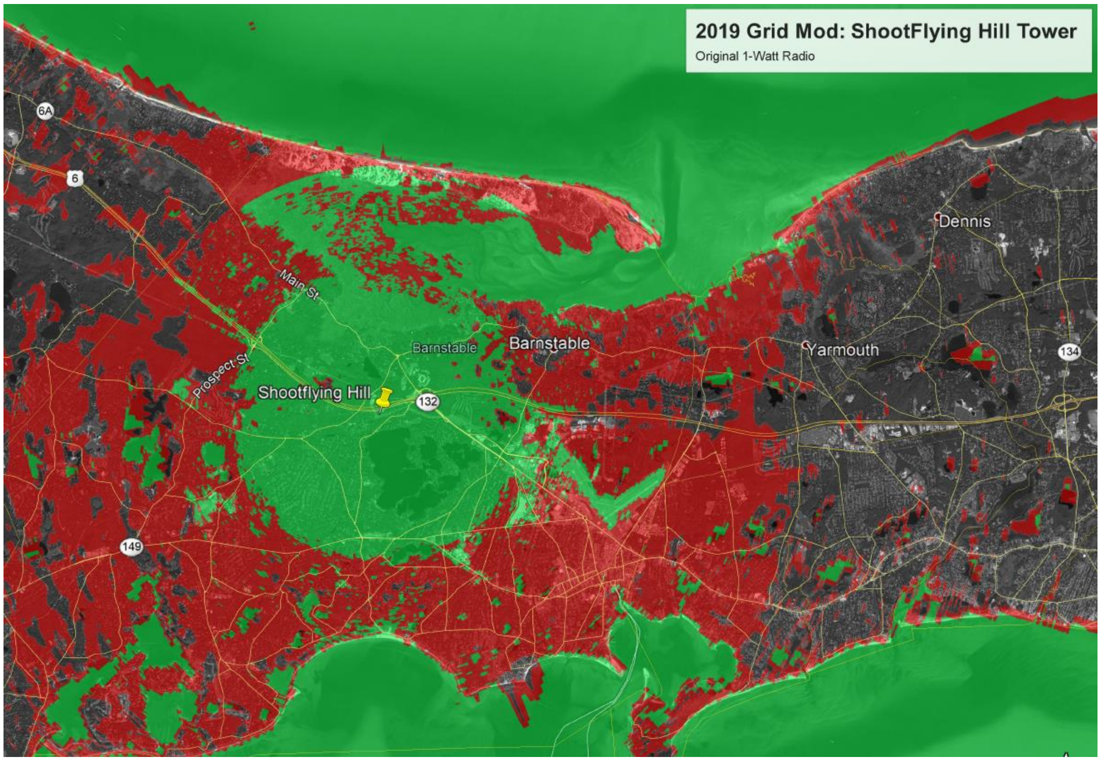
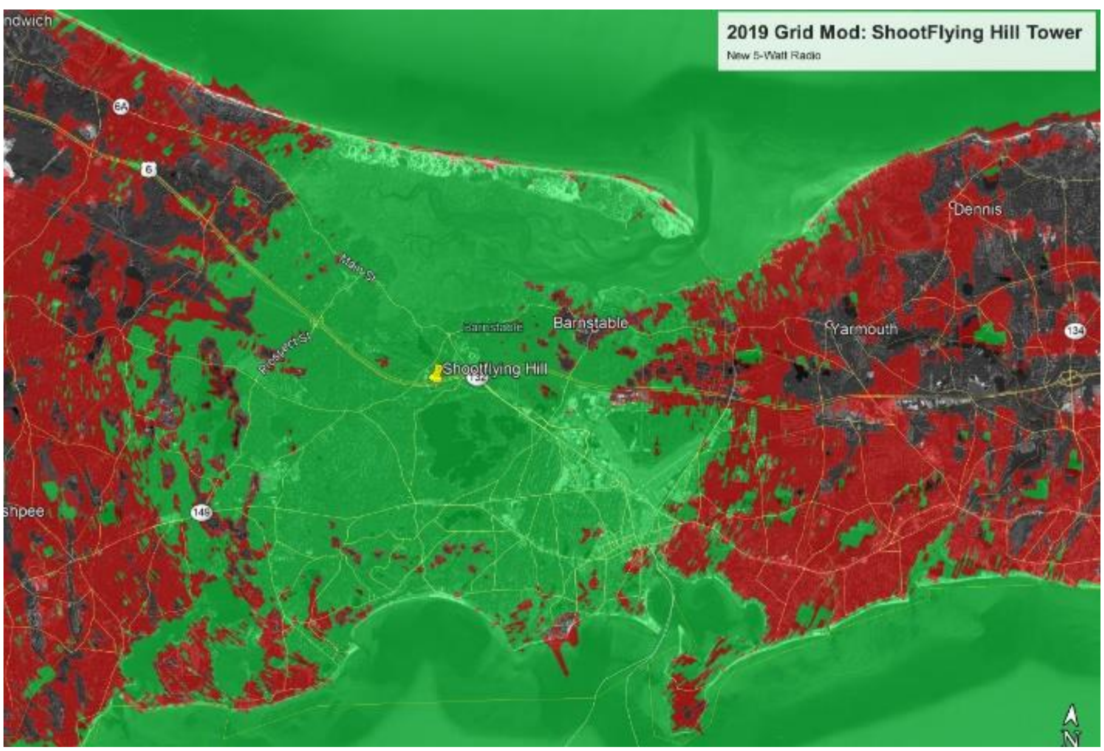


Figure 44 Shoot Flying Hill – New Master Radio After (Before and After Coverage)



Shoot Flying Hill was an existing radio Master that provided minimal coverage. Multiple repeaters were required to extend the signal to remote switches. The new Master radio, a licensed 5-Watt radio, added under the GMP in 2019 provides added coverage, allowing the Company to supplement the existing Master radio, significantly reducing the need for repeaters. Having a large number of repeaters in a radio network introduces latency which can negatively impact performance. Not only does the new radio master provide added coverage, it also allows for improved radio network performance.

Figure 45 Shoot Flying Hill and EMA Southern Region – New Radio Master Installation Coverage Before (450MHz and 900MHz)

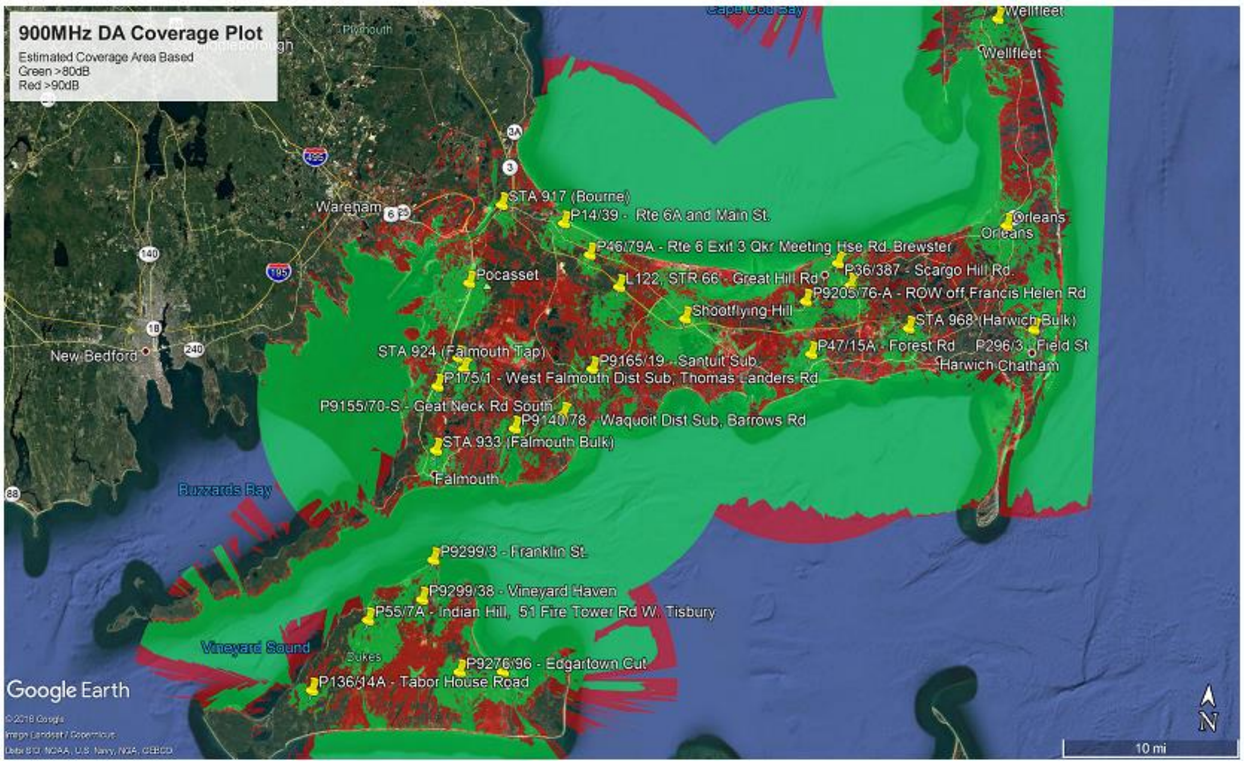
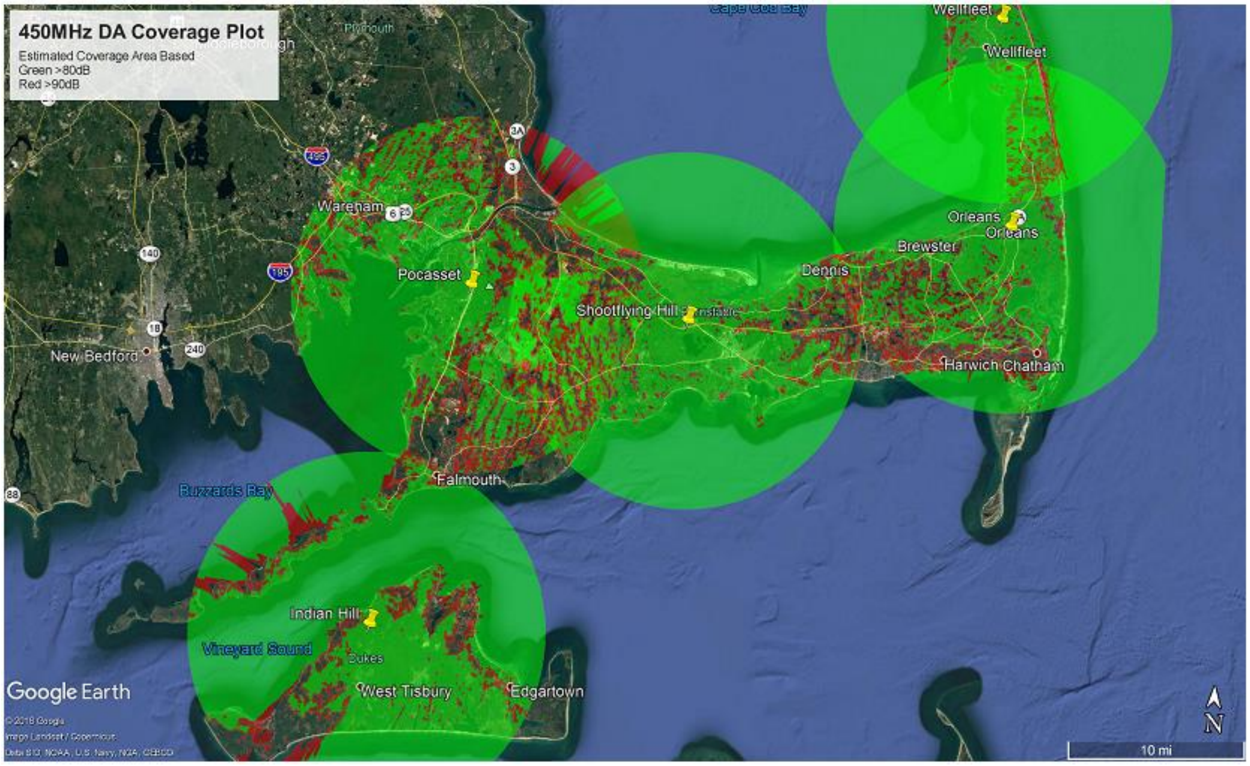


Figure 46 Shoot Flying Hill and EMA Southern Region – New Radio Master Installation Coverage After (450MHz and 900MHz)



The plots above show the difference in coverage between the 450MHz and 900 MHz radios. Green is considered to be a strong signal. As seen from the coverage plots above, with fewer 450MHz master Radios (first picture –

Figure 45), the Company will be able to cover most of the Cape Cod area with good signal compared to the numerous existing 900 MHz radios (second picture –

Figure 46). These maps depict the future expansion plan to install more 450 MHz master radios while retaining a few 900 MHz radios to accomplish a strong and continuous coverage for the cape.

As part of the GMP work plan in the western region, the installation of the new 4RF (450MHz) in Pelham and the CalAmp (450MHz) in Pocumtuck will allow for extended radio coverage which will reach new devices that were previously not covered. Additionally, this system will add more capacity to allow for current cellular and Tait radio system devices to be transferred into the Company's packet data radio system.

The Tait System is currently at the end of its useful life and any devices attached to this system must be transferred to another means of communication. The GMP nodes deployment will allow for the transition of the Tait system to be replaced in the Company's western region.

Other benefits to the newly installed 450MHz nodes in Pelham and Pocumtuck include:

The addition of several of the new VVO and recloser devices into the Company's communication infrastructure with higher fidelity; and

The ability to move cellular connected devices to the new radio locations where connectivity was marginal, thus both increasing communications quality and lowering recurring cell connectivity costs.

Refer to the Figure 47 and

Figure 48 below for a general coverage map associated with the commissioning of the nodes at Pelham and Pocumtuck in the Company's western Massachusetts region. There were no "before" coverage maps for use as a comparison.

Figure 47 Pelham – New Radio Master Installation Coverage

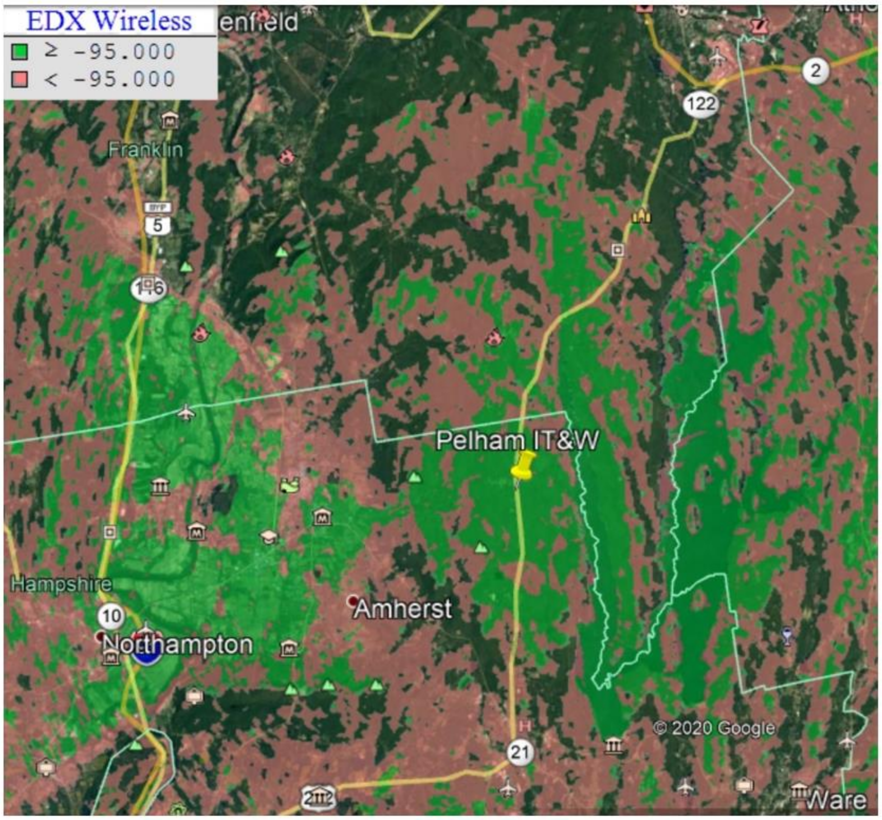
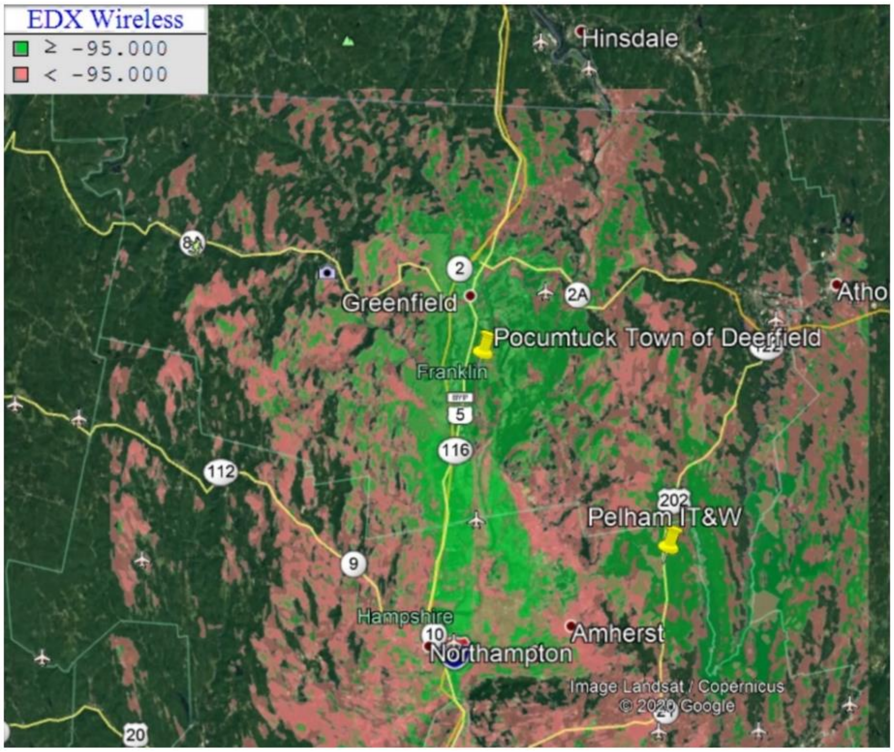


Figure 48 Pocumtuck – New Radio Master Installation Coverage



The Company's original total capital costs were estimated at $2M for the 2018-2020 GMP and $3.5M for the supplemental 2021 GMP plan. The actual total capital costs for the deployment of the 10 nodes (including the D-200 upgrades), and inclusive of the six carryover locations, is $5.7M. A significant portion of this will be the replacement of the field device radios at many locations in order to communicate over the 450 MHz frequency, once it is operable.

29. Lessons Learned/Challenges and Successes

(a) ADSS Miles of Fiber

After completion of detailed engineering, the project review process determined that the Fiber project did not demonstrate a reasonable benefit relative to the cost to customers. In its GMP filing in D.P.U. 15-122 regarding communications investments, the Company had originally planned to build out 250 miles of fiber to connect distribution substations across Massachusetts into the Company's existing fiber network. Based on the results of its engineering analysis, the Company determined the per mile cost of deploying fiber averaged approximately four times the original estimate, chiefly due to the identified and designed make-ready work. The needs assessment determined that although this fiber build out would augment and reinforce the Company's communications infrastructure for future grid modernization investments, the additional fiber was not required to deliver any of the benefits associated with the 2018-2021 GMP. The decision not to move forward with the fiber program was reviewed and approved by the Company's Grid Modernization Executive Steering Committee.

(b) Nodes

Knowing that augmenting wireless communications infrastructure is a cost-effective option to ensure increased throughput of data transmission, the Company continued with this program as originally anticipated, i.e., by utilizing the 900MHz licensed and unlicensed spectrum. However, the Company also seized the opportunity to develop, design and install several nodes on the 450MHz spectrum. Though the 450MHz spectrum has a lower bandwidth, the lower frequency system, coupled with higher-powered radios, will allow for greater wireless communications penetration. This will allow for better fidelity to devices that had communication challenges on the 900MHz frequency.

Multiple visits by field personnel during installation and commissioning, and the need for various contracted resources placed strain on the program execution. This was particularly true of the 450 MHz deployment. Integration of the new 450 MHz system into the Company's recently upgraded SCADA system proved to be more challenging than expected. However, there were programming requirements which required specialized personnel from the vendor, to complete. This included a modest increase in costs and a significant impact on project duration.

30. Description of Benefits Realized as the Result of Implementation

The immediate benefits from this program are namely the increased coverage areas with the upgraded radio node locations and the ability to process significantly more communication traffic via the upgraded front-end processors of the SCADA system. Additionally, the Company expects that the deployment of the 450MHz radio master nodes will provide even deeper and more comprehensive coverage and penetration into areas of challenge. Refer to Appendix 1 for the year-to-year and overall portfolio implementation/deployment data. For further analysis, refer to "Massachusetts Grid Modernization Program Year 2021 Evaluation – Communications" which will be provided by Guidehouse (formerly Navigant Consulting) on June 1, 2022.

31. Description of Capability Improvement by Capability/Status Category

Although the Company all but eliminated the fiber optic deployment, there were six key locations to which fiber optics from a near-by backbone were connected in order to experience a much higher level of fidelity and bandwidth. This increased communications capability will allow for more data points to be transmitted, more frequently, which provides better visibility into the electric power system.

The capability improvements associated with the upgrade or addition of radio nodes within the territory provide for an expanded coverage area which will allow locations that may have previously been inaccessible by radio to now have remotely monitored and/or control equipment installed and commissioned into the Company's system in an efficient and effective manner.

In addition to the nodes, upgrades to the Company's front-end SCADA processing units were completed to allow for the significant increase in deployed field devices, as part of the GMP, to communicate with the Company's SCADA system.

As discussed above, in 2019 the Company elected not to move forward with the fiber optic installations due to significant cost increases that outweighed the benefits associated with that investment. However, the Company recognizes that a successful GMP must have a robust and efficient communications network. To that end, the Company pivoted its node deployments to include a new 450MHz system. This 450MHz system will work in conjunction with the 900MHz system but will allow for increased penetration, particularly in dense areas.

32. Key Milestones

(a) Nodes

- Added data concentration capacity at key locations, adjacent to the Company's SCADA interfaces.
- Successfully commissioned the first 450MHz master radio station in the western region in 2021.
- All carry over work, including the first 450MHz deployment in the eastern region, will be completed by Q2, 2022.
- Diversification of the radio network by adding master radios and eliminating single points of failure.
- Provided a larger footprint of the Company's Private radio network, providing better coverage and less dependency on third parties – cellular providers

(b) ADSS Miles of Fiber

- Deploying fiber optics to key GMP substations and closing more rings for diversification.
- All carry over work is being constructed and is expected to be completed in Q2, 2022.

F. Energy Storage

1. Performance on Implementation/Deployment

Refer to Figure 49 below for the Company's 2018-2021 implementation unit and spending summaries for the Energy Storage GMP Investments.

Figure 49: 2018-2021 Energy Storage Implementation Capital Spending Summary ($)

Investment Category	Preauthorized Device Type	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2018-2021 Actual	2018-2021 Projection*	% Difference
Energy Storage	Martha's Vineyard	958,654	1,305,943	945,977	(3,210,574)	-	3,598,506	-100%
	Provincetown	624,690	1,722,882	15,362,063	22,350,958	40,060,593	45,996,635	-13%

(a) Outer Cape Battery Energy Storage System ("BESS")

i. Overview

The Outer Cape BESS project will be constructed as a 24.9 MW / 38 MWh lithium-ion battery system, located on approximately 1.4 acres at the Provincetown transfer station on land leased from the Town of Provincetown.

The Outer Cape BESS project's primary purpose is to provide backup power during outages on Line 96, a single, three-phase distribution line that serves as many as 11,000 customers from the towns Wellfleet, Truro, North Truro, and Provincetown.

Line 96 starts at the Wellfleet substation and extends along Route 6, going east to Provincetown. Due to its proximity to harsh Atlantic winds and weather conditions, Line 96 has poor reliability statistics, making it an appropriate candidate for the BESS project and the reliability improvements it is anticipated to provide to customers.

An analysis was completed on the six largest Department reportable outages on line 4-96-96 and the circuits it supplies from 2019-2021. This analysis has concluded that the BESS would have reduced total customer outage hours for all three years by 86 percent (COH reduced from 52,015 to 7,223 COH). Total customers affected would have been reduced by 84 percent (from 52,421 to 8,217 customers). This analysis did not evaluate outages beyond the largest six reportable events. The BESS is the system that includes the battery energy storage ("BES") facility and 24 automated devices across the three towns Wellfleet, Truro and Provincetown. This expected reduction is much higher than previous estimates because four of the six events were faults very close to the station 976 and source breaker. These four affected all of the 10,600 customers on line 4-96-96. This large reduction assumed for these outages that all automatic restoration programs and devices worked successfully and restored non-faulted customers in less than one minute based on exact fault locations. In all of the six events the stored capacity of the BES was adequate to sustain all non-faulted section customers until the line repairs were completed by line crews. The average time for the six events was 66 minutes to restore the large majority of customers affected.

One solution to improve this significant reliability issue for the Company's customers on Line 96 would have been to build a 13-mile redundant distribution line. This line would require construction through a substantial portion of the Cape Cod National Seashore, which would generate potential environmental impacts.

The Eversource engineering team identified this area as the target for a BESS project and was confirmed by Eversource's expert consultant, Doosan, in its preliminary feasibility analysis. The Department approved the Company's BESS project proposal in DPU. 17-05, with a projected cost of $40 million.

ii. Design, Site Selection, and Outreach Activity

Based on the preliminary feasibility analysis, Eversource expected to construct the BESS project in Wellfleet, Massachusetts. However, Eversource and its experts confirmed as part of the final feasibility analysis that siting the BESS project as close to the tip of Provincetown as possible would be the optimal solution to maximize potential benefits for customers on the Outer Cape.

Eversource now estimates that, during times when loading is at lower levels (particularly in the non-summer months), the BESS project could provide backup power for up to 10 hours. This duration would cover most outages. Eversource further estimates that, during summer peak loads, the BESS project will provide between 1.5 to 3 hours of backup power depending on the outage's precise location.

In late 2019, the Town of Provincetown (the "Town") select-board approved the Energy Services Agreement between Eversource and the Town of Provincetown, which outlined the agreement to lease 1.4 acres of Town-owned land at the Transfer Station and construct the BESS.

In January 2020, Eversource continued to work closely with the Town to draft a Memorandum of Understanding (the "MOU"), a requirement of the Energy Services Agreement. The MOU outlines commitments Eversource made to the Town and requirements for the construction and operation of the BESS. The MOU was executed in February 2020.

In 2021, Eversource continued to work closely with the Town, implementing regular meetings with staff from its various departments to discuss construction progress and continued coordination at the Transfer Station.

In addition, Eversource conducted multiple fire safety trainings with Provincetown first responders, obtained feedback and established safety protocols. Outreach to abutting property owners was conducted throughout the year through regular project mailings, door-to-door outreach, email updates, and representatives available on-site during major construction activities to quickly mitigate any issues that arose from the work.

iii. Permitting

The Outer Cape BESS project permitting process is substantially complete. Local permits were secured from the Provincetown Planning Board, Zoning Board, Select Board, and Conservation Commission. Permits or approvals were also secured from the Massachusetts Department of Transportation and the Massachusetts Department of Fisheries and Wildlife Natural Heritage & Endangered Species Program. Eversource has also secured a Landfill Post-Closure Minor Modification Permit from the Massachusetts Department of Environmental Protection.

iv. Project Costs

Through December 31, 2021, the Company has expended approximately $40.1 million for the Outer Cape BESS project. Additional details can be found in Appendix 2.

v. Updated Projections for Remainder of 2021-2022 GMP

Project costs for the Outer Cape project are currently estimated at approximately $49.8 million relative to the initial, conceptual-level cost estimate of $40 million presented in DPU. 17-05. The additional cost is driven by the following:

- enclosing the BESS in a building instead of containerized system;
- scope additions to install the NFPA69 Ventilation System for added fire safety and explosion prevention;
- micro-grid equipment upgrades and distribution automation; and
- schedule extension for commissioning equipment.

(b) Martha's Vineyard BESS (2018-2021)

i. Overview

On November 30, 2017, the Department authorized NSTAR Electric to undertake Phase 1 of the Martha's Vineyard BESS project ("Phase 1" or "Project") consisting of a 4.9MW/20 MWh BESS on Eversource-owned land at the Oak Bluffs Service Center located on Martha's Vineyard. Martha's Vineyard BESS project's primary purpose was to significantly reduce reliance on five diesel-fired peaking generators on Martha's Vineyard that are used to supply power to the Island during high load conditions.

The Martha's Vineyard Phase 1 Project conceptual grade estimate was $15M. This estimate was based on a per-MWh cost projection prepared by a consulting company with experience on BESS projects. At the time, the Company presented its case in D.P.U. 17-05, the $15M cost estimate represented the best approximation of the project cost available to the Company. The project was presented to the Department as a demonstration project.

On May 17, 2021, the Company provided notice of project cancellation in relation to the Martha's Vineyard BESS to the Department in D.P.U. 21-30 - NSTAR Electric Company d/b/a Eversource Energy 2020 Grid Modernization Annual Report. The Company's Notification to the Department is included as D.P.U. 21-30 - Storage Update.

At that time the Company completed the third phase of the feasibility analysis for the Martha's Vineyard project, including detailed engineering and site evaluation, along with a detailed cost schedule. Based on the third-phase feasibility analysis, the Company decided to cancel the project due to increased project costs and updated information regarding the future load forecast for Martha's Vineyard. The increased load forecast indicated the need for the construction of a 5th submarine cable to the island. Construction of a 5th submarine cable will eliminate the usefulness of the Martha's Vineyard BESS. The new cable will allow for the retirement of the diesel generators on Martha's Vineyard without the need for the BESS. This, coupled with the total project forecast increase to $23.4 million, caused the Company to discontinue the Martha's Vineyard BESS project.

ii. Project Costs

Through December 31, 2021, the Company has expended approximately $3.2 million for the Martha's Vineyard BESS project. Currently the Company does not expect to incur any further costs for this project. Additional details can be found in Appendix 2.

33. Lessons Learned/Challenges and Successes

The Company is immersed in developing the BESS projects and has developed a strong cross-functional team to develop these projects. Lessons learned in 2021 are as follows.

(a) Competitive Procurement

In June 2020, the Company received notification from NEC Energy Solutions, the engineering, procurement and construction ("EPC") company, that they were exiting the energy storage business. The Company, together with NEC, worked diligently to develop and execute a viable plan to ensure the Energy Storage Projects were successfully built and energized. The parties continue to meet regularly to keep communication lines open and ensure proper execution of the plan.

Since the Company's 2020 GMP Annual Report was filed with the Department, the project team issued various miscellaneous engineering and equipment contracts to support ongoing work. This work was awarded to Suppliers based on a competitive bid that supports the entire Eversource service territory or a BESS project-specific bid.

(b) BESS Safety

Review the latest National Fire Protection Association ("NFPA") standards to ensure compliance and conduct a hazard analysis to establish the appropriate fire safety and other associated systems needed for the projects, continuously monitor for updates as implementation progresses.

The NFPA 855 fire code, a new standard for the Installation of Energy Storage Systems, was initially published on July 26, 2019, and a Tentative Interim Amendment was issued effective on April 21, 2020, which addressed the minimum water flow density and the requirements for

UL9540A Installation level tests. This has been issued since the approval of the BESS projects in D.P.U. 17-05, and the Company incurred additional costs to construct the BESS projects, specifically the Outer Cape BESS, in compliance with the new code requirements. The Company has consulted with NEC Energy Solutions and industry experts to ensure the Outer Cape BESS project will immediately disconnect from the grid in the event of any trouble warning and will be equipped with the leading BESS fire suppression equipment, including chemical suppression, water suppression, and ventilation systems. The Company also engaged local fire departments and first responders early in the process to understand their information needs and desire for design review.

The Outer Cape BESS facility construction has been completed, the referenced fire suppression systems are installed in the facility and their use has been coordinated for maximum effectiveness. The local fire departments and first responders have since been trained in the basics of the BESS, and what their response should be in the event of a battery fire.

The Company obtained information on a BESS fire at an Arizona Public Service ("APS") facility on April 19, 2019 and requested that its vendor undertake a complete fire safety analysis of the BESS design, incorporate lessons learned from Arizona and best practices more generally, and make any further adjustments needed. The Company did not receive a complete fire safety analysis of the APS BESS design. However, the APS report states: "The ERP [Emergency Response Plan] for the McMicken BESS did not have an extinguishing, ventilation, and entry procedure in the event of cascading thermal runaway that would produce significant flammable gases."

The lessons learned from the APS incident include the following:

- Ultimately, there was a lack of information concerning the potentially explosive gas hazard created from unmitigated cascading thermal runaway through an entire battery rack throughout the commissioning process.
- This is demonstrated by the deficiencies in the APSERP, which lacked procedures for extinguishing, ventilation, and entry of the BESS in the event of a cascading thermal runaway.

The Company has reviewed the deficiencies associated with the APS system and undertaken the following actions to mitigate/eliminate the risks that were identified at the APS facility.

<u>Becoming knowledgeable and informed</u>

The Company contracted with NEC Energy Solutions., a BESS supplier with an extensive array of BESS worldwide and in use on a variety of applications. NEC has a Battery Fire Safety Specialist on staff. Eversource personnel have reviewed the latest NFPA standards for the Installation of Energy Storage Systems.

The Company reached out to Duke Energy, a utility with extensive BESS within their system, for information on their best management practices for BESS planning, construction, and operation. Company personnel have thoroughly reviewed the final report from the APS incident – McMicken Battery Energy Storage System Event Technical Analysis and Recommendations; Issue: A, Status: Final Date: July 18, 2020 – for the express purpose of implementing the lessons learned from this incident.

On July 30, 2021, a "Tesla Megapack", a Lithium Ion (li-ion) battery stored in a 25-foot shipping container caught fire during testing near Melbourne, Australia, and brought under control on/about August 2, 2021. The Company will thoroughly evaluate published reports and take action as required to incorporate lessons learned from the Australia incident into its battery systems planning and operation.

<u>Ventilation</u>

A ventilation system is installed to prevent the accumulation of explosive gases that result from battery decomposition from heat, H2, and CO from reaching 25 percent of their lower explosive limit, thus preventing explosions. A comprehensive ventilation system has been incorporated into the Outer Cape BESS.

In addition, since the Outer Cape BESS is adjacent to a closed Municipal Solid Waste landfill, and these types of landfills generate methane gas, the facility will have a comprehensive methane monitoring plan. This plan will include methane monitoring in the battery rooms as part of the ventilation system. Methane will be prevented from reaching 10 percent of its lower explosive limit, further combustion and explosions.

NFPA855 requires BESS to have either an NFPA68 system or an NFPA69 system. The NFPA68 system includes deflagration vents. This system anticipates that there will be an explosion and deflects the force of the explosion up from whatever houses the batteries in a safe direction. The NFPA69 system monitors the atmosphere surrounding the batteries for explosive gases and activates the ventilation system at 25 percent of the Lower Explosive Limit to prevent an explosion. The Company selected the NFPA 69 system for the Outer Cape BESS, as it prevents rather than controls explosions.

<u>Fire protection design and system integration</u>

On July 30, 2021 a "Tesla Megapack", a Lithium Ion (li-ion) battery stored in a 25-foot shipping container caught fire during testing near Melbourne, Australia, and brought under control on/about August 2, 2021. The project, known as the Victorian Big Battery, is under construction with target output of 300 MW / 450 MWh. Once completed, it will consist of around 150 Tesla Megapacks (3 MWh each). It was confirmed that the fire began during initial testing and burned for approximately three to four days. No injuries were reported, and the site was evacuated safely.

Many specific details about the system design, operating status when the fire occurred, monitoring and fire safety are not publicly available, therefore it is difficult to address the incident, make any comparisons and take and preventative measures if needed.

Eversource's battery system design specifications include the following to ensure a similar event will not occur.

Eversource is using Samsung Li-ion batteries that have been UL tested, which indicates that even under thermal runaway conditions, fire propagation does not occur.

The Samsung battery cells in the Outer Cape BESS are wrapped in an epoxy NOVEC sheet for fire prevention.

The NOVEC fire suppression and building ventilation systems are in place, commissioned, and operable. They are controlled by the Aires panel which has a connection to the Building Fire Alarm Panel. The Building Fire Alarm Panel is operational and will send alarms to the appropriate locations when the system receives or detects an alarm.

A water-based sprinkler system is being installed.

During testing, NEC will monitor the batteries 24 hours per day with their AEROS software to detect in advance any conditions which may cause a fire. In addition to monitoring the system remotely, NEC and their subcontractor personnel are on site to ensure effective coordination with the commissioning team.

The commissioning team has prepared a detailed commissioning plan that will safely charge the batteries for testing.

The Company has instituted daily commissioning meetings to discuss testing strategy and monitor progress.

The AEROS system will detect and respond appropriately to harmful system conditions. The system will notify the Eversource control center monitoring the batteries.

When reports are published reviewing the causes of the fire in Australia and any lessons learned, the Company will thoroughly review those reports and adopt any appropriate lessons learned or other best engineering and management practices and incorporate those into its battery systems planning and operation.

(c) Municipal Support

Municipal support continued to be a critical aspect during the construction phase of the Outer Cape BESS. Weekly updates and discussions during regularly scheduled coordination meetings helped ensure clear, concise, and timely communication. Town officials have commended the team not only for excellent communication, but for actively engaging with the Town and being flexible and accommodating.

Municipal officials provided the Company feedback throughout the project. For example, during a fire safety training at the BESS site, the Provincetown Fire Chief recommended that the fire department connection be relocated for enhanced safety measures.

(d) Permitting

There are unique challenges to permitting and site development for new technology projects, particularly in Provincetown, where construction of large utility-scale projects on land adjacent to community land is not typical. Although the BESS project was welcomed in this community, challenges regarding land use (particularly for a development adjacent to a capped and closed landfill), adjacency to residents, natural resource constraints (such as a sole-source aquifer and rare species habitat) had to be surmounted to progress forward due to the relatively remote location and geographical attributes.

Concerns related to the potential contamination of drinking water resources should a catastrophic event occur were a significant issue for the municipality emergency responders, drinking water department, and environmental management department. Additional efforts in the form of groundwater modeling studies and analyses were necessary to address such concerns, as well as inclusion of engineering and design best management practices in the form of secondary containment beneath oil-filled transformer equipment. Even with such studies, the potential impacts to drinking water resources from a catastrophic event at a BESS facility are not a topic that has been studied to any great extent. Proximity to drinking water resources should be a consideration during initial site selection to avoid concerns related to this issue.

Construction of BESS facility at a capped landfill facility also raised concerns by the municipality of potential impacts/disturbance/damage to the capped landfill (in particular the existing landfill gas monitoring and collection system), as well as safety concerns related to build up of combustible landfill gasses within the BESS enclosed battery building. In Massachusetts, the Department of Environmental Protection ("MassDEP") Bureau of Waste Site Cleanup has a specific Post-Closure Use Permit ("PCUP") permit application procedure to review such projects at closed landfills. This permit approval was an extra process that would not be required for a BESS facility proposed at a non-landfill site. As a result of this process and the associated consultation with the landfill owner/operator (the municipality in this case), modifications to the battery building interior combustible gas monitoring systems to include monitoring for methane were agreed to by Eversource as a mitigation and safety measure. The MassDEP PCUP authorization required the building interior gas monitoring system to monitor for methane at concentrations of ≥10 percent of the lower explosive limit and that notifications be sent to Eversource and the MassDEP in the event that methane was detected at this concentration. The BESS facility design already included an interior combustible gas monitoring and ventilation system as a safety feature; however, modifications of the gas monitoring system to accommodate this change under the PCUP authorization were required and carried an extra cost to the Company.

(e) Engineering & New Technologies

The Company has identified that implementation of new technologies must take into account requirements for complex engineering and design of new solutions. For BESS projects this includes islanding and advanced distribution automation schemes that require specialized technical input in areas such as protection and control and communications engineering, which will occur through the bid selection process for an engineering, design and construction vendor.

- Integrating the BESS into the distribution grid required 17 distribution automation reclosers along the 96 circuit. As a prerequisite to installation, this new technology needed to be prototype tested in a lab prior to installation. In future BESS projects, the Company will enhance the testing methodology and update procedures prior to implementation.

- The design of the building and equipment in it included 3D modeling. This modeling is done to ensure optimal arrangement of the equipment, adequate space for access to maintain the equipment, and adequate space for safe movement through the building and around the equipment. During the 3D modeling door swing space was not accounted for. This did not cause any significant problems and will be considered on future projects to ensure ease of maintenance of the equipment.

- The batteries require HVAC systems that have some sound impact. To ensure the BESS will not be audible to the human ear from any surrounding residences or businesses, the Company has constructed sound walls and shrouds, and has housed certain equipment within the battery building.

(f) Turnover to Maintenance/Operations

A checklist was prepared based on experience with past projects to ensure that once commissioning was complete, that the Maintenance and Operation Teams had all the information they needed to smoothly and efficiently, maintain and operate the BESS. Some of the more important components of the Turnover Strategy included the following:

Training and Development of the Operations and Maintenance staff. The staff were trained on a variety of topics, including but not limited to:

- The screens that they would be viewing during operation;

- The alarms and alerts that they would encounter and the attention that should be devoted to each alarm;

- Hands on training on equipment maintenance; Entering the equipment into the Eversource Cascade system that generates the inspection and maintenance schedules for the equipment. New Cascade forms had to be created for some of the equipment that had not previously been used in an Eversource facility. The equipment requiring new Cascade forms included the Li-Ion batteries, the inverters (PCS – Power Conversion System), and the Grounding Transformers used at the facility; and

- Spare Parts Management, including but not limited to :

    - Obtaining item numbers for each spare part;
    - Determining where the spare parts should be stored – on site or remote storage location;
    - Determining if the recommended number of spare parts is appropriate; and

Determining the tools and equipment necessary to install the spare parts.The Company also undertook the following:

- Obtaining all commissioning and test reports to turnover to Maintenance and Operations.
- Obtaining all equipment manuals.
- Finalizing all alarm and alert points and determining their priority.
- Filter storage and frequency of replacement.
- Completing the construction punch list to ensure all is ready for the In-Service Date.
- Obtaining all project drawings including IFCs, As-Builts, and red-lines.
- Ensuring all monitoring and environmental plans are in place.
- Preparation of a site turnover plan from Construction/Commissioning to Operations/Maintenance.
- Developing and distributing a list of emergency contacts to the project team.

(g) Procurement Strategy

The Company also conducted an analysis for a contracting strategy, specifically full EPC including building and BESS versus separate contracts for site preparation, battery facility (container or building), and the energy storage system. The Company determined that a full EPC can limit the contractors that have subcontractors on-site and improve site coordination.

(h) Construction Management

When there were multiple contractors on-site, weekly contractor meetings were scheduled for Monday mornings to review the work going on, the subcontractors doing the work, any work hazards, the various work locations, and needed power requirements.

When large pieces of equipment, such as the switchgear and grounding transformers, were to be delivered to the site, a logistics meeting was held on site in advance of the delivery. All the involved parties were in attendance and discussed the following:

- Placement of crane in advance of delivery considering the path taken by the load from vehicle to placement location;
- Delivery vehicle(s) path and offloading point;
- Location of spotters; and
- Notification of other subcontractors of areas off limits during off-loading and placement of the equipment.

(i) Commissioning

- Obtaining multiple Company department signoffs prior to commencing commissioning phase proved challenging. In future projects, the Company will ensure the system integrator provides a full list of submittals in advance and roles and responsibilities are articulated clearly for timely signoff.

- Effective coordination of electric field operations resources was difficult due to the remote location of the BESS. Going forward, the Company will develop union and non-union resource plans during the pre-commissioning phase and adjust accordingly to reflect the level of effort needed.

- Provincetown BESS controllership was turned over from system dispatch to station operations during commissioning. This enabled provided system operations with additional flexibility to perform electrical switching operations for commissioning activities while maintaining the safe operation of the system.

- In future projects, the Company will ensure engineering design is substantially complete before starting the commissioning phase.

- Synchronization of BESS with the grid proved more challenging than anticipated. Going forward, the Company will develop more detailed specifications for reclosers in coordination with the commissioning team to minimize problems with synchronization in the future.

- During the final phases of commissioning when the BESS is close to ready to be put in service, careful coordination of concurrent on-site commissioning activities is key to ensure safety of both commissioning personnel and the BESS equipment. Daily commissioning calls were held to ensure a safe, coordinated effort on-site each day. Safety is of paramount importance in all Eversource activities and deserves extra awareness throughout commissioning activities.

(j) Martha's Vineyard Lessons Learned

Although the Company ultimately determined to cancel the Martha's Vineyard BESS, the Company has gained substantial knowledge in the following areas, which will prove to be beneficial for future BESS projects:

- System planning and engineering for future BESS projects
- Siting, permitting and municipal outreach and support
- Contracting for EPC and local resources
- Investigation into fire prevention including:
    - fire resistant batteries,
    - fire suppression systems,
    - first responder strategy and training.

34. Description of Benefits Realized as the Result of Implementation

The Outer Cape BESS has not been fully implemented and put into service, therefore benefits realized as the result of implementation cannot be quantified as of this point. When the BESS is placed in service, the Department-approved metrics for its performance and benefits will be tracked and reported to the Department and stakeholders.

35. Description of Capability Improvement by Capability/Status Category

The Outer Cape BESS was designed for the following three use cases:

- Full Islanding & Auto-restoration - the Outer Cape BESS project's primary purpose is to provide backup power during outages on Line 96, a single, three-phase distribution line that runs from Wellfleet to Provincetown.

- Peak Shaving – the Outer Cape BESS can be charged during off-peak hours, when electricity rates are lower. During on-peak hours, the BESS can be discharged to avoid overloading the circuit and higher rate periods.

- Voltage Support—the Outer Cape BESS can provide voltage support by measuring the voltage at the point of interconnection and controlling the reactive power.

36. Key Milestones

Building construction and battery system installation of the Outer Cape BESS project, was completed in July 2021. Key milestones through commissioning are listed below. The Company anticipates that all construction milestone dates are at risk due to commissioning challenges. As currently estimated, upcoming milestones are:

- Commissioning of the BESS commenced in August 2021. Commissioning activities included energizing the Power Conversion System (PCS), battery charging and Point of Interconnection (POI) recloser configuration tests.

- The Company is anticipating commencing operation of the Outer Cape BESS project by July 2022.

G. Electric Vehicles

37. Performance on Implementation/Deployment

Refer to Figure 50 and Figure 51 below for the Company's 2018-2021 implementation unit and spending summaries for the Electric Vehicles ("EV") GMP Investments. Consistent with the Department's directives in D.P.U. 20-69-A, the Company filed, on July 14, 2021, its Phase II EV Infrastructure Program and EV Demand Charge Proposal. The Department docketed the Company's Phase II filing as D.P.U. 20-91. The Company's Phase II filing is currently pending before the Department.

Figure 50: 2018-2021 Electric Vehicles Implementation Unit Summary (# of Units)

Investment Category	Preauthorized Device Type	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2018-2021 Actual	2018-2021 Projection*	% Difference
Electric Vehicles	Electric Vehicles	12	112	181	150	455	500	-9%

Figure 51: 2018-2021 Electric Vehicles Implementation Capital Spending Summary ($)

Investment Category	Preauthorized Device Type	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2018-2021 Actual	2018-2021 Projection*	% Difference
Electric Vehicles	Electric Vehicles	2,859,831	10,979,264	18,075,501	12,842,659	44,757,255	50,916,596	-12%

(a) Background

On November 30, 2017, the Department approved the Company's proposal to spend up to $45 million over five years on the EV Program. (D.P.U. 17-05, at 475-478, 501.)

Consistent with the Department's findings and directives in D.P.U. 15-122 and D.P.U. 17-05, the Company is providing this report on the Make Ready Program's status and achievements, as well as the lessons learned from the Program. This Program update contains operational information including: the number of EV charging stations and sites deployed; site host enrollment; number of EV supply equipment tools installed; costs; and deployment in or adjacent to disadvantaged communities. The Company's progress report also provides information and ideas gathered from the Company's targeted outreach with various stakeholders and work with environmental justice ("EJ") communities and stakeholders.

As part of its proposal in D.P.U. 17-05, the Company proposed to track and report on six proposed performance metrics to evaluate the implementation and customer benefits of the Make Ready Program. D.P.U. 17-05, at 474. In D.P.U. 15-122, the Department noted that it would develop performance metrics for the Program through a separate EV metrics stakeholder process. D.P.U. 15-122, at 187. In the interest of providing the Department and stakeholders with a robust review of the Company's progress to-date under the Make Ready Program, the Company is providing its progress under the six proposed performance metrics first introduced in D.P.U. 17-05. The specific performance metrics include:

(1) total number of "make ready" sites developed;

(2) ten percent capital invested in direct charging ("DC") fast charging sites;

(3) ten percent capital invested in EJ communities;[5]

(4) utilization of EV charging stations separately for Level II chargers and DC fast chargers (measured in annual kWh per port);

(5) the percentage of the Company's residential customers within the range of an Eversource "make ready" site constructed as part of the EV program (i.e., percentage within 20-mile range and within 40-mile range); and

(6) available data on plug-in EV adoption and CO_2 emissions reductions.

(b) Program Overview

Launched in 2018, the Make-Ready Program seeks to help accelerate EV charging infrastructure development within its service territory, encourage EV purchases, and contribute to greenhouse gas ("GHG") emissions reduction in the Commonwealth. The Program is designed to help meet the Commonwealth's goal contained in the Global Warming Solutions Act ("GWSA") and support the campaign of the EEA to encourage zero emissions vehicles ("ZEVs") via a commitment for 300,000 ZEVs registered in Massachusetts by 2025.

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[5] Generally, EJ communities are defined in terms of demographic and socioeconomic characteristics, with certain environmental policy implementation practices aimed at these communities because of race/ethnicity/class-based environmental inequities. The Department directed the Company to select EJ communities that meet two of the following three criteria established by the Massachusetts Executive Office of Energy and Environmental Affairs ("EEA") in Eastern Massachusetts and one of the following in Western Massachusetts: (1) 25 percent or more of the population in the communities must earn 65 percent or less than the Massachusetts median household income; (2) 25 percent of more of the population in the communities must identify as a race other than white; and (3) 25 percent of households lack a person over the age of 14 who speaks only English or speaks English very well.

The Make-Ready Program's primary component is increased investment in long dwell-time EV charging make-ready infrastructure in public and workplace settings and at multi-unit dwellings ("MUDs"). Under the Program, Eversource invests in infrastructure beyond the meter up to the charging station, specifically for the service panel and the associated conduit and conductor necessary to connect each piece of equipment.

The Make-Ready Program was originally designed to run in two phases: Phase I extended from January 1, 2018 through December 31, 2019; and Phase II was designed to extend from January 1, 2020 through December 31, 2022. Over the course of the Program, the Company planned to support the deployment of up to 72 DC fast charging ports at 36 charging sites, and up to 3,500 Level II charging ports at 400 charging sites, throughout its service territory in Massachusetts. Based on customer demand for the Program, in 2019 the Company accelerated implementation of the Make-Ready Program. The original $45 million of preauthorized funds were fully subscribed in the summer of 2020. To maintain momentum, and to continue to help the Commonwealth achieve its stated EV adoption and GHG emissions reduction objectives, additional preauthorized funding was deemed necessary to avoid program interruptions. Therefore, as part of the Company's 2021 supplemental GMP filing, the Company requested an additional $10 million preauthorization in July 2020. The Department docketed that request as D.P.U. 20-74 and subsequently approved the Company's proposal in February 2021. These additional preauthorized funds were intended to support the deployment of up to an additional 100 EV charging sites through the end of the program.

Through this Program, Eversource has supported the deployment of EV charging ports by installing electrical equipment and components necessary to connect EV chargers to its distribution system. Eversource will install the "Eversource-side Infrastructure," and contract with third-party electrical contractors to install behind the meter "Participant-side Infrastructure." Specifically, the EV infrastructure that Eversource is proposing to install and own includes the following: (1) distribution primary lateral service feed; (2) necessary transformer and transformer pad; (3) new service meter; (4) new service panel; and (5) associated conduit and conductor necessary to connect each piece of equipment.

(c) Vendor Prequalification

In the Spring of 2018, Eversource issued a Request for Information / Proposal to begin the process to pre-qualify vendors to participate in the Make-Ready program. This process was undertaken to give EV charging station manufacturers, network integrators, and installers the opportunity to have their equipment and services pre-authorized for inclusion in the Program. Recognizing that new technologies and new vendors may emerge over the duration of the program, Eversource issued a subsequent Request for Proposal in April 2019, to further deepen its bench of partners. A complete listing of these vendors can be found on the program website: https://www.eversource.com/content/ema-c/residential/save-money-energy/explore-alternatives/electric-vehicles/charging-stations/preferred-vendor-list

Being selected indicates that Eversource has reviewed and approved the equipment and services and verified that they meet its specifications and standards, and that the vendors have signed Eversource qualification agreement terms and conditions. Site hosts are welcome to use equipment, installers, or network integrators not selected by Eversource for pre-approval, if those vendors agree to Eversource qualification agreement terms and conditions.

(d) Contractor Qualification

Under the program, Eversource uses third-party electrical contractors for the installation of the "behind the meter" infrastructure. This infrastructure primarily includes the new service panel and enclosure and associated conduit and conductor necessary to connect each piece of equipment.

Eversource chose to use electrical contractors with proven track records already approved by the Company to work on Eversource Energy Efficiency programs. Those contractors include (but are not necessarily limited to):

- Maverick Construction Corporation (Boston, MA)
- J.&M. Brown Company, Inc. (Jamaica Plain, MA)
- Horizon Energy (Taunton, MA)

In 2019, a fourth contractor was added through a response to a Company issued RFP:

- Volta (Boston, MA).

(e) Stakeholder Outreach

Throughout the program thus far, Eversource has presented updates and solicited continual program feedback from multiple stakeholders in the Make-Ready Program. Specifically, the Company met with the Massachusetts Department of Energy Resources ("DOER"); EEA; Department of Transportation; Massachusetts Bay Transportation Authority; Massachusetts Department of Environmental Protection; Environmental Business Council of New England; Sierra Club of Massachusetts; Union of Concerned Scientists; Natural Resources Defense Council; Acadia Center; the Zero Emission Vehicle Commission; Georgetown Climate Center, Green Energy Consumers Alliance; National Grid; Electrify America; Plug-In America; Nissan; General Motors; Tesla; multiple charging station vendors; multiple towns and municipalities in Massachusetts.

In addition to meeting with the various stakeholders identified above, Eversource presented at various forums to help its sight host recruitment and general raise awareness efforts. The Company attended and spoke at quarterly meetings hosted by the Advanced Energy Group to provide regular updates on program status and recent activities, and to solicit and incorporate feedback from the public.

Finally, Eversource maintained close coordination with National Grid through quarterly meetings to share lessons learned and discuss opportunities to collaborate jointly on the deployment of the companies separate yet similar EV programs.

Common themes from stakeholders included general support for the infrastructure program, a need for general market awareness, confirmation of the barriers to DC fast charging implementation, and suggestions regarding the application and legal agreements.

(f) Program Metrics

The following figures provide information on EV Make-Ready charging station projects as of December 31, 2021:

Figure 52: Station Profiles

	Level 2				DC Fast Charger				Total			
	'18	'19	'20	'21	'18	'19	'20	'21	'18	'19	'20	'21
Charging Ports Installed	60	390	857	685	0	0	0	4	60	390	857	689
Charging ports Enabled	85	898	1,615	1,370	0	0	0	4	85	898	1,615	1,374
Avg. # Ports Installed Per Site	5	3	5	5	n/a	n/a	n/a	1	5	3	5	5
Public Sites	8	65	68	75	0	0	0	2	8	65	68	77
Workplace Sites	4	41	73	56	0	0	0	0	4	41	73	56
Multi-Unit Dwelling Sites	0	6	40	17	0	0	0	0	0	6	40	17
Environmental Justice Sites	2	23	31	28	0	0	0	0	2	23	31	28
Annual kWh/port*	**n/a**	**1,542**	**1,026**	**1,762**	**0**	**0**	**0**	**0**	**n/a**	**1,542**	**1,026**	**1,762**

*Annual kWh/port figures are based on the sample size of Make Ready program sites for which the Company has data visibility.

Figure 53: Station Locations

	Level 2				DC Fast Charger				Total			
	'18	'19	'20	'21	'18	'19	'20	'21	'18	'19	'20	'21
Metro Boston	9	67	128	99	0	0	0	0	9	67	128	99
South Coast	1	7	3	11	0	0	0	1	1	7	3	12
Cape & Martha's Vineyard	0	12	16	10	0	0	0	0	0	12	16	10
Western MA	2	26	34	30	0	0	0	1	2	26	34	31
% of residential customers	100	100	100	100	n/a	n/a	n/a	n/a	100	100	100	100

*Please note that historical figures may differ slightly from those included in the Company's previous annual reports. This discrepancy can be attributed to improvements in data reporting and charging station verification procedures that have been implemented over time.

(g) Map

A map of all Electric Vehicle charging stations that have been installed through the Make Ready Program as of December 31st, 2021 can be found by accessing the following link:

https://www.google.com/maps/d/edit?mid=170fhDsYDOd5IEIh29T7BcJQ5NJOvn_mt&usp=sharing

(h) Environmental

Operating under the assumption that each charging port installed incentivizes the adoption of six incremental electric vehicles,[6] the first four years of the Make Ready Program enabled 11,976 EVs (360 in 2018, 2,340 in 2019, 5,142 in 2020, and 4,134 in 2021), equating to an annual CO2 reduction of 41,916 MT (1,260 MT in 2018, 8,190 MT in 2019, 17,997 in 2020, and 14,469 in 2021).

(i) Summary of Interval Charging Data

As indicated in Eversource's Make Ready Program filing in D.P.U. 17-05, the Company intends to include a thorough and inclusive analysis of charging station data as part of its Phase 2 evaluation efforts. In preparation for this work, Eversource has engaged with a data analytics vendor to aggregate, analyze, synthesize, and report on this data. Quarterly, data and analyses are being prepared, reviewed and improved upon in an iterative process to ensure that a quality final analysis will be available for all stakeholders once the program has been fully deployed.

Attachment "Eversource Massachusetts Electric Vehicle Infrastructure Program Charging Station Analysis Report 2021" captures data for 1,195 of the 1,996 ports that have been installed through December 31, 2021. Data for the remaining 801 ports exists, however the Company is still working on establishing the necessary protocols with charging station manufacturers to gain visibility to this information. This has been a key learning thus far and the Company is actively working with charging station vendors to close this gap.

Eversource Massachusetts Electric Vehicle Infrastructure Program Charging Station Analysis Report 2021 is provided as an illustrative example and preview of the more robust analysis that will be performed once the Make Ready program has concluded.

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6 [1] Workplace Charging Challenge, U.S. Department of Energy, https://www.energy.gov/sites/prod/files/2017/01/f34/WPCC_2016%20Annual%20Progress%20Report.pdf

Some of the preliminary conclusions include but are not limited to:

- Stations at Business Offices and Multi-unit dwellings experience longer plug-in times than other venues, with more than 6 hours per charging event.
- A large portion of charging events at Business Offices start earlier in the day, around 7-9 am, most likely when employees arrive for work. Charging events at Multi-unit Dwellings also appear to mostly start at the beginning of the day.
- Weekday peak is during the late morning hours, whereas the weekend has a less defined peak with high periods around mid-day.
- The total number of unique users at Program charging stations has consistently increased over time.
- Each market segment appears to have unique load curves

(j) 2022 Implementation Plans

The deployment of the $55 million preauthorized under the original $45 million proposal and subsequent $10 million expansion is expected to be fully deployed by the summer of 2021.

As noted above, to continue building on the successful implementation of this program, Eversource filed a Phase II proposal with the Department in July 2021. The Phase II Program builds upon the Company's first Program by providing offerings to meet the diverse needs of all the Company's customers, building the infrastructure required to support statewide EV adoption, and helping to enable the Commonwealth's broader transition to a clean transportation future.

Eversource proposed a nearly $200 million, four- year plan that, if approved, will provide incentives for continued expansion of make-ready infrastructure at commercial customer locations, a residential program, support for light-duty fleets, and equity pilots to offer transportation electrification solutions to customers in EJ Communities.

In total, the Phase II proposal intends to add close to an additional 25,000 ports across the Eversource service territory.

38. Lessons Learned/Challenges and Successes

The first four years of Make Ready Program implementation have provided numerous opportunities to learn and adjust processes to manage towards optimization. Lessons learned related to operational execution, site host recruitment and market segmentation have been gleaned and the Company has taken action to course-correct as appropriate. Specific lessons learned are listed below.

(a) Operational execution

- ***Timelier legal agreements:*** steps have helped to reduce the time it takes for legal documents to be executed and facilitated timelier infrastructure deployment.

- ***Modifying Use Cases based on Costs to Scale:*** consolidating to a single level 2 use case allows the Company to standardize electrical infrastructure equipment and enable procurement efficiencies.

- ***Initial ports installed:*** Though Eversource has installed the infrastructure to support 10 charging ports at the majority of sites where feasible, the average number of ports installed in the first four years of the program has been 5 per site.

- ***Need for additional electrical contractors:*** The project team issued a subsequent RFP in 2019 to establish a wider network of electrical contractors throughout the Commonwealth.

- ***Standardization:*** to the extent possible, site design and engineering and equipment has been standardized to provide consistent station configurations across the infrastructure that Eversource owns as part of the Make-Ready program both to reduce costs through the ability to scale and to maximize deployment efficiency

- ***Building channel and supply chain in the Northeast:*** two RFPs were used to create a pre-qualified bench of contractors, vendors, installers and manufacturers for the program. Ongoing vendor workshops and weekly conferences are conducted to coordinate support

- ***Every site is unique:*** Being diligent in upfront engineering and design work is key to limiting surprises and unexpected cost adders during the construction process.

- ***Costs:*** Average site costs have continued to trend down during the program's duration

- ***COVID 19 Impacts:*** COVID-19 has had unforeseen impacts on consumer behavior, including electric vehicle purchasing, driving and charging behavior in 2020, which are still evolving. Nationally, the trends from large charging station network operators showed a significant decline in utilization in 2020. In April, 2020, EVgo, one of the country's largest charging networks, reported the amount of time that customers are using its stations has dropped by more than half. And Electrify America, the Volkswagen AG subsidiary that runs the nation's largest network of public chargers, reported a 60 percent decline in utilization rates. Tesla, in May 2020, reported a 70 percent drop in utilization in North America. Similar trends occurred locally on the stations installed as part of the Company's

Make-Ready program. Despite more stations continuing to be installed by the Company's Make Ready program throughout 2020, in October, the total average daily kWh used across the installed chargers is still only approximately 66 percent of the average from January – March of 2020. Planning horizon for EV impacts are closer to 10 years than one. While overall public EV charging load declined in 2020, the Company continued to deploy EV infrastructure in line with the Commonwealth's long-term goals. The Company did not anticipate that the trends and impacts of 2020 would be long lasting or permanent. In 2021, station utilization began to recover. The Company anticipates charging behavior to return to normal behavior levels in 2022. Because of these impacts, however, the data collected on charging stations in 2020 and 2021 may not be useful to drawing conclusions in a business-as-usual scenario.

(b) Site host recruitment

- ***Site host marketing***: Marketing the Make-Ready program to potential site hosts is a high touch sales effort supported by tailored marketing content.

- ***Equipment incentives***: Rebates or incentives are helpful in defraying or eliminating the cost of the EVSE to the site host and eliminating barriers to participation in the program.

- ***Understanding operational issues:*** Customers have looked to Eversource to understand the impact of what pricing levels might have on demand, and on their overall charging operations; the Company has provided guidance on strategies to increase utilization and manage demand.

- ***Customer interest exceeded expectations:*** Eversource's site host recruitment efforts to date have been very successful for Level 2 charging, and the Program was fully subscribed in October 2020. The Company filed, and received subsequent approval, for an additional $10 million preauthorization to continue building on the successful deployment of the program.

- ***Customer appetite for larger deployments:*** While the Program was initially designed with the intention to spread customer dollars across as many sites as possible, having the flexibility to selectively choose exceptions where a greater number of chargers makes sense and helps to accelerate EV adoption is beneficial to advancing the Commonwealth's goals.

(c) Market Segmentation

- ***Multi-Unit dwellings***: Successfully recruiting multi-unit dwellings to be site hosts requires a deliberate effort.

- ***Customer-owned distribution networks:*** Primary metered customers who were initially flagged as good targets based on parking characteristics (large, publicly accessible, long dwell-time, highly utilized), were ineligible under the original Program design.

- ***Environmental Justice Communities:*** The Company actively participates in cross-jurisdictional internal groups with its affiliates and other utilities and collaborates with stakeholders representing disadvantaged and low-income communities.

- ***DC Fast Chargers:*** The Company concluded that there are two primary barriers to customers willing to be site hosts for DC fast chargers: 1) the high upfront cost of the hardware/software; and 2) high anticipated operating costs.

- ***Barriers to EV Adoption:*** As part of the original proposal, Eversource identified several barriers to EV adoption including the upfront cost of EVs, lack of available charging infrastructure and EV range; recent market studies continue to affirm the same barriers to EV adoption exist today.

39. Description of Benefits Realized as the Result of Implementation

As detailed in Section G.1.f (Implementation Metrics), the deployment of the 455 charging station sites with 1,996 installed ports in the first four years of the program supports 11,976 incremental EVs on the road, resulting in an annualized CO2e reduction of 41,916 MT.

40. Description of Capability Improvement by Capability/Status Category

This category is not applicable to the Make Ready Program.

41. Key Milestones

Below is a summary of key milestones achieved throughout the course of the program:

January 2018: Project and Construction leads assigned to Eversource implementation team

March 2018: Presented DC Fast Charger Deployment Plan to EEA/DOER/DOT

April 2018: Request for Information / Proposals issued to qualify EV charging station vendors

April 2018: Site host recruitment efforts initiated

May 2018: Site host agreement / license forms finalized

June 2018: Pre-qualified vendors selected

June 2018: Third-party electrical contractors selected

July 2018: First site host contract executed

October 2018: First charging station site electrified

December 2018: Launched website: https://www.eversource.com/content/ema-c/residential/save-money-energy/explore-alternatives/electric-vehicles

April 2019: Additional charging station vendors qualified through subsequent Request for Proposal

June 2019: Finalized development of standardized panel enclosure

September 2019: Received 500th customer intake application

December 2019: Electrified 1st Multi-Unit Dwelling site

December 2019: Electrified 100th customer site

July 2020: Requested additional $10 million in preauthorized funding from the MA DPU to continue program spending thru 2021

October 2020: 400th contract signed; program fully subscribed

December 2020: Electrified 300th customer site

October 2021: Electrified 1st DC Fast Charging site

December 2021: Electrified 455th customer site

IV. Term Description and Report on Each Infrastructure Metric

As part of its approval of the Company's GMP, the Department approved the proposed statewide and company-specific infrastructure metrics. Regarding statewide infrastructure metrics, the Department required the Distribution Companies to report on the following: (1) system automation saturation; (2) number/percentage of sensors installed versus planned; (3) percentage of circuits with installed sensors; and (4) total number of grid-connected DG facilities, nameplate capacity and estimate output of each unit and type of customer-owned or operated units. D.P.U. 15-122, at 198-199. As for the Eversource-specific infrastructure metrics, the Company is required to report on the following for each category of preauthorized grid-facing investment: (1) the number of devices or other technologies deployed; (2) the associated cost for deployment; (3) reasons for deviation between actual and planned deployment for the GMP investment year; and (4) projected deployment for the remainder of the GMP term. Id. at 200-201. To assist in the development of these baselines, the Department directed each of the

Distribution Companies to develop and maintain information on its system design, operational characteristics (e.g., voltage, loading, line losses), and ratings prior to any deployment of preauthorized grid-facing technologies. Id. at 203. Additionally, the Department directed the Distribution Companies, when developing their proposed baselines to use, to the extent possible, information reported in the annual service quality ("SQ") filings, as well as other publicly available information. Id.

While the purpose of these infrastructure metrics is to determine how system performance can be changed because of grid modernization investments, there are outside factors, over which the Company has no control, that can and will impact performance. Weather, customer behavior, economic conditions and other factors will have a significant influence on the parameters being measured under these metrics.

The statewide infrastructure metrics use the following common definitions across the Distribution Companies.

Grid Modernization Device - any device that meets the requirements of either a fully automated or a partially automated device.

Fully Automated Device – a device that meets all the following requirements:

- reacts to system conditions to isolate or restore portions of the electric system;
- communicates system quantities (e.g., voltage, trip counts) to a central location, such as SCADA; and
- the state of the device can be remotely controlled by dispatch.

Partially Automated Device – a device that meets at least one of following requirements:

- Reacts to system conditions to isolate or restore portions of the electric system;
- Communicates system quantities (e.g., voltage, trip counts) to a central location, such as SCADA;
- The state of the device can be remotely controlled by dispatch; or
- Be capable of upgrade to a fully automated device without full replacement.

Sensor – Equipment that sends or records information of the electric system that can be used to improve the efficiency or effectiveness of workforce or asset management (e.g., Fault locators that would help pinpoint a problem for more efficient crew deployment).

Statewide Infrastructure Metrics

1.1 Grid Connected Distribution Generation Facilities

The data used in the calculation of this metric consider units that have an executed Interconnection Service Agreement ("ISA") and are in service and connected to the distribution system.[7]

The Company has tracked the following data on a substation and circuit basis:

a. Total number by technology or fuel type – count of units by technology or fuel type

b. Nameplate capacity by technology or fuel type – sum total of nameplate capacity

c. Estimated output by technology or fuel type – sum of nameplate capacity * capacity factor * 8760 hours

d. Type of customer-owned or operated units by technology and fuel type – (i.e., count of Photo Voltaic ("PV"), wind, Combined Heat and Power ("CHP"), Fuel Cell, etc.)

e. Nameplate as a Percent of Peak Load – calculated as total nameplate capacity (MW) / peak load (MW)

The baseline for this metric has been quantified and calculated based upon units in service by December 31, 2017. Please refer to the Company's Baselines and Targets Filing for the detailed baseline quantities.

The 2021 results for this metric are summarized in the table below. The 56,629 facilities at the end of 2021 represent an increase of 21,516 facilities over the baseline amount of 35,113. The increase was primarily driven by PV facilities. The supporting details can be found in Attachment 2021 SI-1.

Table SI-1

Grid Connected Distribution Generation Facilities 2021

	Baseline	2018	2019	2020	2021
Number of Distributed Generation Facilities	35,113	40,374	45,427	50,442	56,629

[6] It is important to note that DER developers' decisions regarding DER interconnection may be influenced by tax incentives, subsidies, and costs and availability of the technology, which, in turn, will influence these metrics.

1.2 System Automation Saturation

This metric measures the automation saturation by customer served by fully automated or partially automated device. The terms "fully automated" and "partially automated" refer to feeders for which Eversource has attained optimal or partial, respectively, levels of visibility, command and control, and self-healing capability through the use of automation.

The baseline saturation rate has been calculated based on what existed on the Eversource system as of the date the baseline was first calculated on August 1, 2018. Customers that can benefit from multiple devices will be counted as one for purposes of calculating the baseline. The installations will not be limited to the main line infrastructure and will include no-load lines and distribution system supply lines.

The following matrix has been provided as guidance to determine which type of equipment would be considered partially automated, fully automated or included as a sensor.

Device Type	Not Included	Partial Automation	Full Automation	Included as a Sensor
Feeder Breakers (No SCADA)		X		
Feeder Breakers (SCADA)			X	X
Reclosers (including sectionalizers, single phase reclosers, intellirupters, ASU) (No SCADA)		X		
Reclosers (including sectionalizers, single phase reclosers, intellirupters, ASU) (SCADA)			X	X
Padmount Switchgear (No SCADA)		X		
Padmount Switchgear (SCADA)			X	X
Network Transformer/Protector with full SCADA			X	X
Network Transformer/Protectors with monitoring, no control		X		X
Network Transformer/Protector with no SCADA	X			
Feeder Meter (e.g., ION, with comms)				X
Capacitor and Regulator with SCADA		X		X
Capacitor and Regulator no SCADA	X			
Line Sensor (with comms)				X
Fault Indicator (with comms)				X
Other Fault Indicators (no comms)	X			
Other Voltage Sensing (with comms)			X	X
Sectionalizer (no SCADA)		X		
Sectionalizer (SCADA)			X	
Customer Meter	X			
Distribution /step down Transformer	X			
Other Substation Breakers	X			
Fuse	X			

As more automation is installed on the Company's system, both under the GMP and pursuant to other system investment outside of the GMP, the results of this metric will be reduced.

Metric Calculation:

Customers Served

Fully Automated Device + 0.5*(Partially Automated Device)

The baseline for this metric has been quantified and calculated based upon equipment in service as of August 1, 2018. Eversource's baseline is 247.1. The calculated score at the end of 2021 was 184.0. This is an improvement of 63.1 over the baseline amount of 247.1. In 2021, the Company identified an inconsistency in the methodology used to calculate the results of this metric when compared to the baseline period. The Company has recalculated the 2018 through 2021 results to ensure a consistent comparison to the baseline period. Please see attachment 2021 SI-2 SI-3 for circuit level detail. The Company has also attached the original baseline and the restated results for 2018 through 2020.

Table SI-2

System Automation Saturation 2021

	Baseline	2018	2019	2020	2021
Total Saturation Score	247.1	234.7	209.3	198.2	184.0

1.3 Number/Percentage of Circuits with Installed Sensors

This metric measures the total number of electric distribution circuits with installed sensors[8] which will provide useful information for proactive planning and intervention. The installation of sensors provides the means to enable proactive planning and measure several grid modernization initiatives such as VVO and asset management. A sensor analytics development program is an essential part of grid modernization and provides the visibility into network operations needed to move toward an effective grid modernization program.

The baseline for this metric consists of all sensor installations on Eversource's distribution circuits and substations, including existing installations.

The baseline for this metric has been quantified and calculated based upon equipment in service as of August 1, 2018. Eversource's baseline has been calculated as 82.3 percent. Please see the Company's Baselines and Targets Filing for the circuit detail used to develop the baseline.

For 2021, Eversource's number and percentage of circuits with installed sensors has increased to 85.9 percent. Please see Table SI-3 below for further details. Please see attachment 2021 SI-2 SI-3 for circuit level detail. The Company has also attached the original baseline and the metrics results for 2018 through 2020.

[8] Please see the previous matrix for devices that have been defined as "sensor" for the purpose of determining whether a circuit has a sensor.

Table SI-3

Number/Percentage of Circuits with Installed Sensors 2021

	Baseline	2018	2019	2020	2021
Percent with Installed Sensor	82.3%	82.4%	83.7%	85.1%	85.9%
Percent without Installed Sensor	17.7%	17.6%	16.3%	14.9%	14.1%
Number of Feeders with Installed Sensor	1,727	1,709	1,735	1,800	1,826
Number of Feeders without Installed Sensor	371	366	339	315	299

Eversource-Specific Infrastructure Metrics

2.1 Number of devices or other technologies deployed

Under this metric, Eversource has tracked the following information per GMP investment at the substation and circuit level where appropriate:

a. Number of devices or other technologies deployed

b. Total number of devices planned

c. Percent – Number of devices installed / total number of devices planned

This metric is strictly a GMP deployment metric: accordingly, the baseline for this metric necessarily starts at zero to ensure that pre-GMP investments are not captured in the baseline.

Please refer to Table S2-1 below for the Company’s GMP investment deployment through 2021.

Table S2-1

Number of Devices or Other Technologies Deployed (Units)

Investment Category	Preauthorized Device Type	2018-2021 Actual	2018-2021 Projection*	2018-2021 Percent (%)
Monitoring & Control (SCADA)	Microprocessor Relay	202	237	85%
	4kV Circuit Breaker SCADA	54	67	81%
	Recloser SCADA	59	59	100%
	Padmount Switch SCADA	59	59	100%
	Network Protector SCADA	91	104	88%
	Power Quality Monitors	39	34	115%
Distribution Automation	OH DA w/o Ties	334	343	97%
	OH DA w/Ties	53	53	100%
	4kV Oil Switch Replacement	172	172	100%
	4kV AR Loop	18	34	53%
Volt-Var Optimization	VVO - Regulators	97	144	67%
	VVO - Capacitor Banks	74	106	70%
	VVO - LTC Controls	8	12	67%
	VVO - Line Sensors	205	229	90%
	VVO - IT Work	N/A	N/A	N/A
	Microcapacitors	154	299	52%
	Grid Monitoring Line Sensors	262	411	64%
Advanced Distribution Management System (ADMS)	Advanced Load Flow	N/A	N/A	N/A
	GIS Survey (Expense)	N/A	N/A	N/A
	Dist. Management System	N/A	N/A	N/A
	Forecasting Tool	N/A	N/A	N/A
	Synergi Upgrades	N/A	N/A	N/A
	PI Asset Framework	N/A	N/A	N/A
Communications	Numbers of Nodes	10	14	71%
	Miles of Fiber	2	0	N/A
Electric Vehicles	Electric Vehicles	455	500	91%
Energy Storage	Martha's Vineyard	N/A	N/A	N/A
	Provincetown	N/A	N/A	N/A
	Total Units	2,348	2,877	

* Information contained within the *2018-2021 Projection* column was based on the projections made as part of the 2020 GMP Annual Report

2.2 Associated cost for deployment

Under this metric, the Company has tracked the following information per investment type at the substation and circuit level where appropriate:

a. Cost of devices or other technologies deployed

b. Total cost of devices planned

c. Percent – Cost of devices installed / total cost of devices planned

Please refer to Table S2-2 below for the Company's associated cost for deployment through 2021.

Table S2-2

Cost for Deployment ($)

Investment Category	Preauthorized Device Type	2018-2021 Actual	2018-2021 Projection*	2018-2021 Percent (%)
Monitoring & Control (SCADA)	Microprocessor Relay	34,359,319	41,351,117	83%
	4kV Circuit Breaker SCADA	18,259,341	19,932,413	92%
	Recloser SCADA	3,385,470	3,385,867	100%
	Padmount Switch SCADA	1,006,763	1,006,989	100%
	Network Protector SCADA	1,433,958	2,148,174	67%
	Power Quality Monitors	710,985	1,170,506	61%
Distribution Automation	OH DA w/o Ties	24,709,155	26,175,729	94%
	OH DA w/Ties	3,255,816	3,252,790	100%
	4kV Oil Switch Replacement	30,194,757	29,003,272	104%
	4kV AR Loop	2,296,669	2,460,937	93%
Volt-Var Optimization	VVO - Regulators	3,986,740	6,061,931	66%
	VVO - Capacitor Banks	3,571,796	2,860,086	125%
	VVO - LTC Controls	1,452,402	2,397,267	61%
	VVO - Line Sensors	1,432,698	1,234,836	116%
	VVO - IT Work	2,677,280	2,628,525	102%
	Microcapacitors	1,115,116	2,250,675	50%
	Grid Monitoring Line Sensors	592,053	1,500,000	39%
Advanced Distribution Management System (ADMS)	Advanced Load Flow	8,962,796	8,808,889	102%
	GIS Survey (Expense)	-	-	N/A
	Dist. Management System	1,596,259	8,000,001	20%
	Forecasting Tool	1,843,343	3,246,003	57%
	Synergi Upgrades	942,445	767,003	123%
	PI Asset Framework	1,076,564	986,498	109%
Communications	Numbers of Nodes	2,406,701	5,734,556	42%
	Miles of Fiber	1,146,668	1,565,513	73%
Electric Vehicles	Electric Vehicles	44,757,255	50,916,596	88%
Energy Storage	Martha's Vineyard	-	3,598,506	0%
	Provincetown	40,060,593	45,996,635	87%
	Total Capital Spending (and # of Units)	237,232,943	278,441,314	85%
	Preliminary O&M**	16,558,338	15,760,806	105%
	Preliminary Total Spending	253,791,280	294,202,120	86%

* Information contained within the *2018-2021 Projection* column was based on the projections made as part of the 2020 GMP Annual Report

**2021 O&M spending will be finalized at the time of the Company's Grid Modernization Factor ("GMF") filing due to be filed by May 15th, 2022

2.3 Reasons for deviation between actual and planned deployment for the plan year

Under this metric, the Company tracked the following information per investment at the substation and circuit level where appropriate:

a. Number of devices or technology installed versus plan for a given year

b. Cost of devices or technologies installed versus plan for a given year

c. Reason for differences between planned and installed.

Please refer to Table S2-3 below for the variance between actual and planned deployment for the 2018-2021 GMP. The following section summarizes the reasons for variances during the term.

Table S2-3

Grid Modernization - 2021 Unit vs. Cost Deployment

Investment Category	Preauthorized Device Type	2018-2021 Actual	2018-2021 Projection*	2018-2021 Percent (%)	2018-2021 Actual	2018-2021 Projection*	2018-2021 Percent (%)
Monitoring & Control (SCADA)	Microprocessor Relay	34,359,319	41,351,117	83%	202	237	85%
	4kV Circuit Breaker SCADA	18,259,341	19,932,413	92%	54	67	81%
	Recloser SCADA	3,385,470	3,385,867	100%	59	59	100%
	Padmount Switch SCADA	1,006,763	1,006,989	100%	59	59	100%
	Network Protector SCADA	1,433,958	2,148,174	67%	91	104	88%
	Power Quality Monitors	710,985	1,170,506	61%	39	34	115%
Distribution Automation	OH DA w/o Ties	24,709,155	26,175,729	94%	334	343	97%
	OH DA w/Ties	3,255,816	3,252,790	100%	53	53	100%
	4kV Oil Switch Replacement	30,194,757	29,003,272	104%	172	172	100%
	4kV AR Loop	2,296,669	2,460,937	93%	18	34	53%
Volt-Var Optimization	VVO - Regulators	3,986,740	6,061,931	66%	97	144	67%
	VVO - Capacitor Banks	3,571,796	2,860,086	125%	74	106	70%
	VVO - LTC Controls	1,452,402	2,397,267	61%	8	12	67%
	VVO - Line Sensors	1,432,698	1,234,836	116%	205	229	90%
	VVO - IT Work	2,677,280	2,628,525	102%	N/A	N/A	N/A
	Microcapacitors	1,115,116	2,250,675	50%	154	299	52%
	Grid Monitoring Line Sensors	592,053	1,500,000	39%	262	411	64%
Advanced Distribution Management System (ADMS)	Advanced Load Flow	8,962,796	8,808,889	102%	N/A	N/A	N/A
	GIS Survey (Expense)	-	-	N/A	N/A	N/A	N/A
	Dist. Management System	1,596,259	8,000,001	20%	N/A	N/A	N/A
	Forecasting Tool	1,843,343	3,246,003	57%	N/A	N/A	N/A
	Synergi Upgrades	942,445	767,003	123%	N/A	N/A	N/A
	PI Asset Framework	1,076,564	986,498	109%	N/A	N/A	N/A
Communications	Numbers of Nodes	2,406,701	5,734,556	42%	10	14	71%
	Miles of Fiber	1,146,668	1,565,513	73%	2	0	N/A
Electric Vehicles	Electric Vehicles	44,757,255	50,916,596	88%	455	500	91%
Energy Storage	Martha's Vineyard	-	3,598,506	0%	N/A	N/A	N/A
	Provincetown	40,060,593	45,996,635	87%	N/A	N/A	N/A
	Total Capital Spending	237,232,943	278,441,314	85%	2,348	2,877	
	Preliminary O&M**	16,558,338	15,760,806	105%			
	Preliminary Total Spending	253,791,280	294,202,120	86%			

* Information contained within the *2018-2021 Projection* column was based on the projections made as part of the 2020 GMP Annual Report
**2021 O&M spending will be finalized at the time of the Company's Grid Modernization Factor ("GMF") filing due to be filed by May 15th, 2022

Throughout the course of the 2018-2021 GMP, the Company was diligent and specific with the decisions made in order to: 1) execute the program efficiently; 2) stay within the total authorized budget cap; and 3) meet all Department directives. As a result of executing a multi-year portfolio of programs, there were many factors that affected the three elements noted above. Some of these factors and the variations they caused were due to taking on a significant amount of incremental work, developing new internal/external project teams, managing an unprecedented pandemic, resourcing, shifting plans to accommodate emergency response to weather events, executing on new technologies and various other factors which are discussed and illustrated in the Company's prior annual reports and in the areas below:

- In Section III of this Term Report
- In the Appendix 1 attachment of this Term Report
- In the Guidehouse (formerly Navigant, Inc) evaluations which will be submitted in June 2022.

A. Distributed Energy Resources ("DER")

1. Overview of DER on the Distribution System

Installations of DER are growing at an unprecedented rate in many parts of the United States, including in Massachusetts where state policy directives have incentivized and accelerated DER deployment in support of the Commonwealth's clean energy and climate goals. In its Massachusetts territory alone, Eversource is currently processing applications for solar distributed generation totaling about 1,977 MW, ranging from the high-volume residential roof top to large multi-MW stand-alone projects. Figure 54 below shows the number of applications for simplified (less than 15 kW) and expedited/standard (15 KW to over 5 MW) projects in 2021. These proposed projects come at a time when the Company's electric distribution infrastructure in many key areas, especially Southeastern Massachusetts ("SEMA"), is already saturated with DER that has been interconnected primarily over the last 10 years, incentivized in large part through the Commonwealth's previous solar incentive programs, including its Solar Renewable Energy Certificate-I and II programs, and the SMART program. This surge in DER deployment on the Company's electric power system ("EPS") is expected to continue for the foreseeable future.

Figure 54: 2021 Interconnection Applications

Territory	Status	Simplified	Expedited/ Standard	Totals
EMA	Applications Online in 2021	4,861	251	5,112
	Applications Received in 2021	5,798	628	6,426
WMA	Applications Online in 2021	1,344	24	1,368
	Applications Received in 2021	1,691	90	1,781

B. Lessons Learned Integrating DERs

The challenges associated with integrating this large amount of DER into the Company's electric power system ("EPS") are numerous and require solutions on several levels, from technological to process-driven to policy. Eversource has enhanced its ability to study and determine the impacts of high DER penetration on the EPS and on its customers and developed innovative tools and methods to identify mitigation measures for safely and reliably interconnecting DER, as well as optimal solutions that address long-term system needs. Eversource has developed and invested in applications and processes to streamline the application, study, and approval process for DER projects. Eversource has also worked with the Department (in D.P.U. 19-55 and D.P.U. 20-75) to address current barriers to the continued growth of DER in Massachusetts through changes that are consistent with long-term objectives for cost allocation and design of the EPS. Across this spectrum of solutions, one consistent underpinning is that upgrades to the Company's EPS are necessary (especially in highly saturated areas) to allow DER to successfully integrate and consistently generate energy when it's needed, in locations where it can be accommodated.

Based on Eversource's experience, there are new complicating factors that are now evolving in the market that require more technical review time and integrated system work to ensure the safety and reliability of the system. These factors include the emergence of:

1. Increased deployment of solar coupled with energy storage including DOER SMART program requirement for storage for all projects over 500 kW.

- The addition of energy storage to solar interconnection requests has added complexity to DER studies and screens as well as metering and incentive program applicability.
- Applicants are interested in maximizing incentive programs across state and Independent System Operator ("ISO") markets which can lead to confusion on application tracks.

2. Substation upgrades

- Due to high saturation levels in several areas of the system, (e.g., SEMA) system impact studies are determining that substation upgrades, significant upgrades in some cases, are required to allow for project interconnection. This has the potential to make study and construction activities more complicated and time-consuming. It also requires the Company's planning teams to account for the potential for additional substation work or dedicated/express feeders due to the expected continuing DER activity. The Company must ensure that resources are utilized, and projects are executed in an efficient manner, which requires careful planning and coordination across several engineering disciplines. Also, as discussed in D.P.U. 20-75 and other forums, optimal planning must take into account future DER in the queue to make appropriate long-term design decisions for the largest number of Distributed Generation ("DG") customers. The Company is currently executing several large group studies in Eastern and Western Massachusetts to understand these implications and develop equitable methods for allocating the costs of these necessary upgrades across multiple customers.

3. More frequent ISO transmission studies

- ISO is requiring studies for projects less than 5 MW in areas it deems saturated. This adds time, cost and engineering effort to many projects that historically did not have this extra layer of administrative and engineering complexity. Utilities and Transmission Groups are performing more level 0/1 and level 3 transmission studies[9] and, in some cases, doing them in groups to process them more quickly than if they were processed sequentially. ISO and Eversource work together on the study process to minimize customer impact, but Eversource is aware that these new requirements are confusing to customers.

4. New metering and design configurations

- Metering configurations vary based on system design and/or incentive program (e.g., ISO program participation, SMART program energy storage adder) requiring additional design effort and resources.
- Multiple service requests on single parcel and/or building (dedicated service for the DER which is separate from the existing customer) add complexity to the interconnection study process.

5. Aggregation of small projects in certain areas

- Over time the number of small projects interconnected in an area leads to significant installed capacity.
- Simplified applications for multiple small projects in the same area require additional study and administrative and engineering burden to execute outside of the normal simplified process.

Eversource has participated in the D.P.U. 19-55 discussions with DER stakeholders to work on alignment and updates to the statewide Interconnection Tariff. Discussions have been targeted on topics such as group studies, cost allocation, metering, communications, energy storage, Affected System Operator (ASO) Studies and ISO market participation.

Eversource is constantly exploring opportunities to better manage its DER grid interconnection processes in ways that can more fully leverage technology advancements (e.g., advanced inverter functionalities), enable procedural transparency, and recognize evolving technical standards.

Eversource recognizes first that a core group of technical experts is needed to further streamline the application studies and effectively adapt to the changing dynamics. Accordingly, the Company has hired and is currently hiring additional engineers, analysts, customer service

[9] ASO transmission studies are required when a DG applicant's project has the potential to impact existing saturation levels at a substation that might have implications to Eversource's transmission system or to other transmission companies or bulk power operators.

representatives and program managers. In 2020, the Company rolled out the Power Clerk online application tool for the Simplified process and then rolled out the Expedited/Standard track for applications in 2021. This provides customers with an improved application experience and allows customers to track their projects status in real time. Ultimately the additional labor resources and Power Clerk tool will:

- further streamline the interconnection process;
- help customers track the progress of their projects in real time;
- support customers' application process and reduce manual errors;
- further refine and improve the Company's interconnection processes; and
- provide developers/customers with additional information during the application process.

Additionally, the Company has rolled out and is continually exploring initiatives associated with mapping tools. Accurate, up-to-date maps of the distribution system can play a useful role for both the Company and potential DER interconnection applicants. For the Company, having this information can support a more rapid review of an interconnection application on a specific feeder. For applicants, having access to a more dynamic version of the map, specifically one that indicates remaining hosting capacity for new DER projects, allows them to be more selective in the types and locations of projects and their specifics (e.g., capacity, technology deployed, etc.) to pursue in a formal interconnection application. By increasing visibility into the characteristics and feasibility of individual circuits, these maps can save both customers and the Company time and money.

In February 2022, the Company published updated hosting capacity maps. The new map provides a segment level hosting capacity for all areas of the service territory using Synergi Electric's automated incremental hosting capacity analysis. While a previous version of the map used static data to produce one value for a given circuit, the new process provides potential DER interconnection applicants with visibility into how a hosting capacity value can change based on the location of a section on a given circuit. The new maps evaluate a hosting capacity solution against four criteria: static voltage, voltage variation, thermal capacity, and reverse power flow. These improvements to hosting capacity maps are a direct result of capabilities enabled by the Company's 2018-2021 GMP. In 2020, the Company implemented Synergi Electric as a fully automated system-wide load flow tool enabling a 2021 grid modernization project that added analytical functionality required to produce more accurate and granular (segment-level) hosting capacity maps on a monthly basis.

C. Performance Metrics

1. Description of Report on each Performance Metric

In D.P.U. 12-76-B, the Department directed Eversource, National Grid and Until (collectively, the "Distribution Companies" or "Companies" and individually, a "Distribution Company" or "Company") to include in their respective GMPs performance metrics that measure progress towards the objectives of grid modernization. D.P.U. 12-76-B, at 30. Eversource filed proposed performance metrics with its GMP in D.P.U. 15-122, as did National Grid and Unitil in each of their respective GMP dockets. The Department determined that additional work was needed to develop performance metrics that appropriately track the quantitative benefits associated with pre-authorized grid-facing investments, and progress toward the grid modernization objectives. D.P.U. 15-122, at 95-106. The Department ordered the Distribution Companies to file revised proposed performance metrics designed to address the preauthorized grid-facing investments and noted that it would convene a stakeholder process to facilitate review of the revised performance metrics. Id. at 202.

On August 15, 2018, the Distribution Companies filed revised proposed performance metrics. Following that filing, the Department, the Department of Energy Resources ("DOER") and the Cape Light Compact ("Compact") issued information requests to the Distribution Companies regarding the revised proposed performance metrics. On February 13, 2019, the Department held a technical conference to aid its review of the Distribution Companies' revised proposed performance metrics. Following the technical conference, the Department issued a Memorandum on March 19, 2019, ordering the Distribution Companies to file further revised performance metrics consistent with the directives set out in the Memorandum. March 19, 2019 Memorandum at 2-5. The Companies submitted final revised proposed performance metrics on April 9, 2019.

On July 25, 2019, the Department stamp approved the Companies' proposed performance metrics dated April 9, 2019. This section of the Grid Modernization Annual Report describes the statewide, as well as Company-specific, performance metrics that Eversource is using to evaluate progress towards the grid modernization objectives. Please note that, as the statewide metrics apply to Eversource, National Grid and Unitil, this section of Eversource's 2018-2021 Grid Modernization Term Report will refer to all three Distribution Companies when describing the statewide metrics. For each performance metric, this section will identify the type, objective, assumptions, calculation approach, organization of results, and baselines.

The Department also ordered the Distribution Companies to develop a formal evaluation process, including an evaluation plan and evaluation studies, to review the Distribution Companies' preauthorized GMP investments and their progress toward meeting the Department's grid modernization objectives. D.P.U. 15-122, at 204-205. Guidehouse (formerly Navigant Consulting, Inc.) is completing the evaluation to ensure a uniform statewide approach and to facilitate coordination and comparability across the Distribution Companies.

The data supporting the performance metrics have been provided to the Guidehouse evaluation team by the Company. Results of the Monitoring and Control ("M&C"), Distribution Automation ("DA"), Volt-Var Optimization ("VVO"), and Advanced Distribution Management System ("ADMS") investment areas are expected to be shared by Guidehouse in June 2022, as stated in the response to DPU-EP-1-1, which was filed in D.P.U. 15-122 on February 6, 2020. The performance metrics are based on statistical analyses and case studies for the M&C and DA investment categories, performed by the evaluation team using data provided by each Distribution Company and were evaluated in 2022 to allow adequate data collection to be completed.

The underlying data that supports several of the performance metrics can also be found in the Appendix 1 Templates Grid Mod Term Report 2018-2021

The next section provides the accompanying details behind the performance metrics. As noted above, the results of these metrics and supporting analysis will be provided by Guidehouse in the Evaluation Reports to be filed in June 2022. It is important to note that as part of Information Request D.P.U. EP-1-1, filed on February 6, 2020, and the revised "GMP Stage 3 Eval Plan (Revised 12-1-20)" filed on December 1, 2020, Guidehouse provided some updates, modifications, and enhancements to the evaluation plan, as it relates to the approved performance metrics. The following matrix has been provided to summarize the relationship between each performance metric and its associated investment category.

	Investment Category					
Metric	**M&C**	**DA**	**VVO**	**ADMS**	**Comms**	**ALF**
Volt Var Optimization (VVO) Baseline			X			
VVO Energy Savings			X			
VVO Peak Load Impact			X			
VVO Distribution Losses w/o AMF (Baseline)			X			
VVO Power Factor			X			
VVO – Energy and GHG Impact			X			
VVO Related Voltage Complaints Performance Metric and Baseline			X			
Increase in Substations with DMS Power Flow and Control Capabilities				X		
Control Functions Implemented by Circuit (VVO, Auto Reconfiguration)				X		
Numbers of Customers that benefit from GMP funded Distribution Automation Devices		X				
Reliability-Focused Grid Modernization Investments' Effect on Outage Durations	X	X				
Reliability-Focused Grid Modernization Investments' Effect on Outage Frequency	X	X				
Advanced Load Flow - Percent Milestone Completion						X
Eversource Customer Outage Metric (Average Zone Size)		X				

(a) Volt Var Optimization and conservation voltage reduction Baseline

Volt VAR Optimization and Conservation Voltage Reduction ("VVO/CVR") is a solution that reduces energy consumption and demand without the need for customer interaction or participation. The core principle behind VVO/CVR is that load is more optimally utilized at lower voltages. The primary focus of VVO/CVR is to reduce circuit demand and energy consumption by flattening and lowering voltage profile on the circuit while maintaining customer service voltage standards. In addition, VVO/CVR systems allow for more gradual and responsive control of reactive power devices, such as capacitors, which will help improve the overall system power factor and reduce system losses. VVO/CVR allows customers to realize lower consumption without experiencing a reduction on the level of comfort and service.

Quantifying the exact impact of VVO/CVR is difficult to achieve given the Companies' current level of visibility into their systems. In a VVO/CVR system, the Companies will not have visibility into exactly what customer loads are being impacted, nor will they be able to identify the impact of the VVO/CVR system at any specific point in time. In order to have this level of visibility, the Companies would need to have interval metering at each residential customer's premises. At this time, none of the Companies have this level of residential metering. The metrics discussed below are all based on a measurement and verification ("M&V") process, which uses a statistical process to quantify the impact the VVO/CVR system has on the customers it serves.

1.1.1 Type of Metric

Statewide Performance Metric

1.1.2 Objective

Establish a baseline impact factor for each VVO enabled circuit which will be used to quantify the peak load, energy savings and greenhouse gas ("GHG") impact measures.

1.1.3 Assumptions

VVO dynamically controls and coordinates multiple devices to manage both voltage and reactive power. System-wide efficiency is achieved by simultaneously coordinating operations using continuous measurements from multiple sensors distributed across the circuit.

Once a circuit has VVO enabled, a M&V process will be performed through operating VVO using a predetermined time period and series. Based on the results of this M&V process, a circuit level VVO impact and baseline will be created.

1.1.4 Calculation Approach

The following data will be tracked and reported on a substation and circuit basis:

a. Determine circuit loads through measurements during on/off periods.
b. Apply temperature corrections.
c. Develop load profiles.

As part of the baseline data capture, each VVO circuit will capture hourly circuit data for real and reactive power.

Time	P (kW)	Q (kVAR)
1:00 AM	4298	1949
2:00 AM	4061	1542
3:00 AM	3284	1574
4:00 AM	3408	1277
5:00 AM	2896	1519
6:00 AM	2900	1200
7:00 AM	3185	1388
8:00 AM	3103	1476
9:00 AM	4006	1868
10:00 AM	3817	1884
11:00 AM	4351	1997
12:00 PM	4635	2323
1:00 PM	5129	2390
2:00 PM	5213	2673
3:00 PM	5517	2677
4:00 PM	5378	2478
5:00 PM	5400	2855
6:00 PM	5658	2986
7:00 PM	5720	2638
8:00 PM	5643	2922
9:00 PM	5290	2664
10:00 PM	5346	2628
11:00 PM	5019	2496
12:00 AM	4801	2667

1.1.5 Organization of Results

This information will be provided for each VVO enabled circuit and serve as the baseline variable for calculating demand reductions or serve as variables for other calculations, such as reductions in GHG emissions. This calculation will be performed once and will support both circuit and system level impacts.

1.1.6 Baseline

The baseline will be calculated through M&V after each circuit and/or substation is placed into service. The Distribution Companies recommend that each VVO/CVR circuit undergo a three to six-month M&V process, the results of which will be used to estimate the impact the system has on system load for the next five years. At the end of five years, the M&V would be repeated to ensure that each Company is using recent and relevant results for metric reporting. Baselines will be reported during the first Annual Report following the field verification.

1.1.7 Results

VVO M&V began in December 2020 across 19 circuits. For the 2020 performance metrics, baseline energy use was calculated for winter 2020/21 using data collected when VVO was disabled. To calculate total baseline energy use, the evaluator constructed models to estimate energy savings to calculate what energy usage would have been in each hour of winter 2020/21 for each VVO feeder had VVO been disabled for the entirety of the season. The evaluator then summed this calculated energy usage across all hours of winter 2020/21 for each circuit to calculate a baseline total energy use for the winter 2020/21 season. Baseline energy use is provided below.

Baseline Energy
113,470 MWh

1.2 VVO Energy Savings

1.2.1 Type of Metric

Statewide Performance Metric

1.2.2 Objective

Quantify the energy savings achieved by VVO using the baseline established for the circuit against the annual circuit load with the intent of optimizing system performance.

1.2.3 Assumptions

Once a circuit has VVO enabled, a M&V process will be performed through operating VVO using a predetermined time period and series. Based on the results of this M&V process, a circuit level VVO impact and baseline will be created.

1.2.4 Calculation Approach

The following data will be tracked and reported upon on a substation and circuit basis:

a. Annual energy delivered in kilowatt hours ("kWh") for 2015, 2016, and 2017.

Energy Savings will be represented by the net impact of VVO using the baseline established for the circuit against the annual circuit load.

1.2.5 Organization of Results

This information will be provided for each VVO-enabled circuit and serve as the baseline variable for calculating demand reductions or serve as variables for other calculations. This will be performed annually, and support both circuit and system level impacts.

1.2.6 Baseline

VVO-related pre-investment baseline of energy delivered in kilowatt hours ("kWh") will be provided for each feeder and substation within the service territory for the years 2015, 2016, and 2017 to the extent that historical metering data are available. For feeders where such data are currently not available, the Companies shall estimate the VVO-related pre-investment baseline of annual energy delivered in kWh and identify these feeders with estimates until the necessary metering in installed.

1.2.7 Results

VVO M&V began in December 2020 across 19 circuits. For the 2020 performance metrics, VVO energy savings were determined via regression models that compared energy use during the VVO engaged state and the VVO disengaged state during the winter 2020/21 period. Baseline energy use and energy savings observed during the winter 2020/21 period are provided in the table below. Savings are not provided for the years 2018 and 2019 as VVO was not yet engaged. The evaluator will provide a new baseline and savings in June 2022 using data collected during 2021.

Baseline Energy	2018 Savings	2019 Savings	2020 Savings	2021 Savings
113,470 MWh	N/A	N/A	853 +/- 124 MWh	To be provided June 2022

1.3 VVO Peak Load Impact

1.3.1 Type of Metric

Statewide Performance Metric

1.3.2 Objective

This metric is designed to quantify the peak demand impact VVO/CVR has on the system with the intent of optimizing system demand.

1.3.3 Assumptions

For this metric, the Companies will utilize active circuit M&V peak demand reduction results from individual circuits. No M&V results older than five years will be used.

1.3.4 Calculation Approach

This metric will use the following data:

- Circuit level M&V estimated hourly demand reduction;
- Circuit level hourly on/off VVO/CVR Status;
- Circuit level hourly peak demand; and
- System Level yearly peak time.

Each Company will apply the corresponding M&V estimated hourly demand reduction on all circuits with active VVO/CVR for the appropriate peak hour. As some circuits have different peak times, using the appropriate demand estimated reduction for the correct hour is important. This will result in a single (GW) estimated demand reduction attributed to VVO/CVR for each Company. Each Company's individual demand reduction attributed to VVO/CVR will be aggregated, resulting in the statewide estimated reduction.

1.3.5 Organization of Results

Each Company will provide individual circuit VVO/CVR performance, GWs estimated demand reduction, as well as the summation of total system impact.

1.3.6 Baseline

VVO-related pre-investment baseline of annual peak load in million-volt ampere ("MVA") will be provided for each feeder and substation within the service territory for the years 2015, 2016, and 2017.

1.3.7 Results

VVO M&V began in December 2020 across 19 circuits. For the 2020 performance metrics, the evaluator used data spanning winter 2020/21 to assess VVO performance. ISO-NE defines the summer on-peak period as 1:00 p.m. to 5:00 p.m. from June 1 to August 31 on non-holiday weekdays. Given VVO M&V did not cover the summer months in 2020, peak demand impacts are not provided for 2020. In addition, since VVO was not engaged prior to 2020, peak demand impacts are not provided for 2018 and 2019. Peak demand baseline and peak demand savings will be provided for 2021 in June 2022. The table below summarizes this information.

Baseline	2018 Savings	2019 Savings	2020 Savings	2021 Savings
To be provided June 2022	N/A	N/A	N/A	To be provided June 2022

1.4 VVO – Distribution Losses without AMF (Baseline)

1.4.1 Type of Metric

Statewide Performance Metric

1.4.2 Objective

VVO reduces circuit demand by flattening and lowering circuit voltages, primarily by using voltage regulators. At the same time, VVO actively controls capacitor banks to maintain circuit power factors near unity. This DA project will implement better voltage regulation to improve power quality and reduce losses. This includes the coordinated operation of a voltage regulator with a transformer load-tap changer at a substation.

Electrical loss in the circuit can be investigated using the difference between power provided by the circuit regulator and the total power delivered to the consumer loads. This impact metric presents the difference between circuit load measured at the substation via the SCADA system and the metered load measured both at the substation and at line devices capable of capturing load over the necessary intervals.

1.4.3 Assumptions

There are many elements that contribute to differences between circuit load data and the hourly measurements. These factors include:

- Unmetered load, such as street lights;
- Electricity theft; and
- Circuit line losses.

1.4.4 Calculation Approach

Using hourly data for real and reactive power, one can determine hourly line losses. This represents both technical and non-technical, e.g., theft, losses.

1.4.5 Organization of Results

This information will be provided on an annual basis for VVO-enabled circuits. Results will be based upon the results at the end of each calendar year.

1.4.6 Baseline

The baseline for line losses will need to be developed once the circuit is enabled and the data is captured. The baseline for this metric will be reported in the first annual report after the M&V is completed.

1.4.7 Results

VVO M&V began in December 2020 across 19 circuits. For the 2020 performance metrics, the evaluator used data spanning winter 2020/21 to assess VVO performance. The evaluator calculated distribution losses that were highly variable and unpredictable across VVO circuits, likely due to insufficient data collected for analysis. As such, the evaluator did not provide an estimate of VVO line losses in 2020. The impact of VVO on line losses is not provided for the years 2018 and 2019 as VVO was not yet engaged. The evaluator will provide a baseline and an estimate of the impact of VVO on line losses in June 2022 using data collected during 2021.

Baseline	2018 Savings	2019 Savings	2020 Savings	2021 Savings
To be provided June 2022	N/A	N/A	N/A	To be provided June 2022

1.5 VVO Power Factor

1.5.1 Type of Metric

Statewide Performance Metric

1.5.2 Objective

VVO reduces circuit demand by flattening and lowering circuit voltages, primarily by using voltage regulators. Simultaneously, VVO actively controls capacitor banks to maintain circuit power factors near unity. Power factor is an indication of how efficiently the distribution system is delivering power. A distribution system operating at unity power factor delivers real power more efficiently than one operating at either a leading or lagging power factor. This performance metric seeks to quantify the improvement that VVO/CVR is providing. However, power factor alone is not sufficient to accurately describe the impact VVO/CVR has on the system. At low demand levels, a poor power factor is not as significant than at high demand levels. Therefore, some qualifications must be made to accurately track power factor.

1.5.3 Assumptions

Performance will be based on circuit level hourly power quality measurements at the substation.

1.5.4 Calculation Approach

This metric will use the following data:

- Circuit level hourly Power Factor;
- Circuit level hourly on/off VVO/CVR Status; and
- Circuit level hourly peak demand.

For this performance metric, only power factors corresponding to greater than 75 percent of a circuit's peak annual demand will be used. This qualified data will then be averaged to provide a circuit by circuit power factor performance metric. These averages will then be used to generate a system power factor performance, weighted by the peak demand of each respective circuit.

1.5.5 Organization of Result

The results of this metric will be reported in a tabular format on a circuit by circuit basis and a total system tally. Power factor is a dimensionless metric.

1.5.6 Baseline

The baseline will be measured with VVO disabled and then again with VVO enabled to develop a baseline. The baseline for this metric will be reported in the first Annual Grid Modernization Report after the M&V is completed.

1.5.7 Results

VVO M&V began in December 2020 across 19 circuits. For the 2020 performance metrics, the evaluator used data spanning winter 2020/21 to assess VVO performance. Given VVO power factor is to be calculated using only power factors corresponding to greater than 75 percent of a circuit's peak annual demand, there was an insufficient number of hours available with which to measure VVO power factor. As such, the evaluator did not provide an estimate of VVO power factor in 2020. The impact of VVO on power factor is not provided for the years 2018 and 2019 as VVO was not yet engaged. The evaluator will provide a baseline and an estimate of the impact of VVO on the power factor in June 2022 using data collected during 2021.

Baseline	2018 Savings	2019 Savings	2020 Savings	2021 Savings
To be provided June 2022	N/A	N/A	N/A	To be provided June 2022

1.6 VVO estimated VVO/CVR energy and GHG impact

1.6.1 Type of Metric

Statewide Performance Metric

1.6.2 Objective

This metric is designed to quantify the overall GHG impact VVO/CVR has on the system. A GHG reduction estimate will be derived from the circuit level energy savings.

1.6.3 Assumptions

For this metric, each Company will utilize active circuit M&V energy reduction results from individual circuits. No M&V results older than five years will be used. To calculate GHG reductions, each Company will use GHG emissions factors consistent with those used in the 2019-2021 Three-Year Energy Efficiency Plans for displaced GHG.

1.6.4 Calculation Approach

This metric will use the following data:

- Circuit level M&V estimated Energy Reduction;
- Circuit level hourly on/off VVO/CVR Status;
- Circuit level hourly energy; and
- GHG emissions factors consistent with those used in the 2019-2021 Three-Year Energy Efficiency Plans.

Each Company will accumulate all hours with active VVO/CVR and use the respective M&V energy reduction estimate, applied against the hourly demand. This will result in a single (GWhr) estimated energy reduction attributed to VVO/CVR for each Company, and, when combined with other companies, statewide.

CO_2 avoided due to VVO/CVR will be calculated by multiplying the above energy reduction by a typical generation emissions factor based upon metric tons per MWh.

$$CO_2\,Emissions(tons) = Energy\ Savings(MWh) \times CO_2\,Emissions\,Factor\left({}^{tons}\!/_{MWh}\right)$$

The calculation will use the GHG emissions factors consistent with those used in the most recent version (currently 2019-2021) Three-Year Energy Efficiency Plans.

1.6.5 Organization of Results

Each Company will provide individual circuit VVO/CVR performance, GWhrs estimated energy reduction, as well as the summation of total system impact.

1.6.6 Baseline

The baseline for this metric will be reported in the first Annual Grid Modernization Report after the M&V is completed.

1.6.7 Results

VVO M&V began in December 2020 across 19 circuits. For the 2020 performance metrics, the evaluator used data spanning winter 2020/21 to assess VVO performance. Using baseline energy and VVO energy reduction estimates for winter 2020/21, the evaluator provided baseline CO_2 emissions and estimated CO_2 emissions reduction for winter 2020/21, provided in the table below. The impact of VVO on GHG emissions is not provided for the years 2018 and 2019 as VVO was not yet engaged. The evaluator will provide a new baseline and an estimate of the impact of VVO CO_2 emissions in June 2022 using data collected during 2021.

Baseline	2018 Carbon Reduction	2019 Carbon Reduction	2020 Carbon Reduction	2021 Carbon Reduction
56,054 tons	N/A	N/A	422 +/- 61 tons	To be provided June 2022

1.7 Increase in Substations with Distribution Management System ("DMS") Power Flow and Control Capabilities

1.7.1 Type

Statewide Performance Metric

1.7.2 Objective

This metric will demonstrate the progress in the m ADMS investment by tracking the substations that have been equipped with power flow capabilities as well as the number of customers benefitting from the technology on each feeder. This metric will support the objective of optimizing system performance and more specifically improve asset utilization, improve reliability and integrate distributed energy resources. ADMS gives system operators increased visibility on the real time output of generating facilities. This metric is designed to demonstrate that the model is an accurate representation of field conditions.

1.7.3 Assumptions

A substation will be assumed to have DMS power flow capability when all feeders are modeled daily with no unwarranted voltage or capacity violations over a consecutive 30-day period.

1.7.4 Calculation Approach

This metric will track and report on the following:

From the time that a substation model is available on a daily basis, for each substation, number of voltage or capacity violations for a consecutive 30-day period, with explanation of any warranted voltage or capacity violations.

In addition, the Companies will report on the number of customers on each feeder benefitting from this technology.

1.7.5 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

1.7.6 Baseline

The baseline for this metric will start at zero since no feeders have been equipped with this technology. A chart with the total number of feeders installed each year along with a detailed report supporting the chart will be provided to support the tracking of this metric.

1.7.7 Results

There are no results to report on this metric due to the planned go-live date of this project. The DMS is expected to go-live at the end of 2023.

1.8 Control Functions Implemented by Circuit (VVO, Auto Reconfiguration)

1.8.1 Type

Statewide Performance Metric

1.8.2 Objective

This metric will show the progress in the ADMS investment by tracking the control functions implemented at the circuit level as well as the number of customers affected by the technology on each feeder. This metric will support the objective of optimizing system performance and more specifically minimize electrical losses and improve reliability.

1.8.3 Assumptions

A control function will be defined as the ability for the DMS to automatically issue command to field devices based on real time system condition, and a circuit will be included in this metric when all devices defined as "fully automated"[10] can be automatically controlled.

1.8.4 Calculation Approach

This metric will track and report on the following:

- Circuits with control function implemented; and
- Type of control function implemented.

In addition, the Companies will report on the number of customers on each feeder affected by this technology.

1.8.5 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

1.8.6 Baseline

The baseline for this metric will start at zero since the specific control functions laid out as part of the Companies' respective GMPs have never been deployed. A table outlining the details behind the control functions implemented at the circuit level will be provided to support the tracking of this metric.

1.8.7 Results

There are no results to report on this metric due to the planned go-live date of this project. The DMS is expected to go-live at the end of 2023.

1.9 Numbers of Customers that benefit from GMP funded Distribution Automation Devices

1.9.1 Type

Statewide Performance Metric

1.9.2 Objective

This metric will show the progress in the DA investment by tracking the numbers of customers that have benefitted from the installation of DA devices. This metric will support the objective

[10] A *Fully Automated Device* meets all the following requirements: reacts to system conditions to isolate or restore portions of the electric system; communicates system quantities (e.g., voltage, trip counts) to a central location, such as SCADA; and the state of the device can be remotely controlled by dispatch.

of optimizing system performance and more specifically reduce the duration and number of customers impacted by outage events. These investments will also allow for a reduction in manual switching operations, reduce operations cost and potentially defer capital upgrades with enhanced flexibility to shift load.

1.9.3 Assumptions

A customer will benefit from DA when their automated zone size is reduced.

1.9.4 Calculation Approach

This metric will track and report on the following:

- Circuit number; and
- Number of customers impacted.

1.9.5 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

1.9.6 Baseline

The baseline for this metric will start at zero since this will be tracking only the customers that benefit from GMP investments. A table with the type of device, circuit number where installed and number of customers benefitted will be provided to support the tracking of this metric.

1.9.7 Results

At the end of the 2018-2021 GMP term over 249,000 customers benefited from GMP-funded DA devices. The circuit level details can be found in the Appendix 1 attachment.

1.10 Reliability-Focused Grid Modernization Investments' Effect on Outage Durations

1.10.1 Type

Statewide Performance Metric

1.10.2 Objective

This metric will compare the experience of customers on GMP DA-enabled circuits as compared to the prior three-year average for the same circuit. This metric will provide insight into how DA can reduce the duration of outages.

1.10.3 Assumptions

Outages and their impact are typically situational in nature. The DA solutions must be capable of performing intended actions in under the one-minute threshold set by the Department. There may be circumstances where more complex FLISR schemes may take longer than one minute, but less than five, to properly locate, isolate and restore an impacted area safely. The circuit must have three years of System Average Interruption Duration Index ("SAIDI") history to be included in the metric. Additionally, numerous factors, such as a Company's tree trimming cycle, weather and vehicular accidents, can impact system reliability, regardless of a Company's grid modernization investments.

1.10.4 Calculation Approach

This metric will track and report on the following:

- Circuit level SAIDI for circuits that have DA enabled in the GMP plan year;
- Three-year average circuit level SAIDI covering the years 2015, 2016, and 2017; and
- Compare the current year circuit SAIDI with the three-year historic average SAIDI of the circuit.

AVERAGE ('CKAIDI 2015'+' CKAIDI 2016'+' CKAIDI 2017') - 'CKAIDI Year n' = if greater than 0, positive impact.

1.10.5 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

1.10.6 Baseline

The pre-investment baseline of a static three-year average circuit level SAIDI in 2015, 2016, and 2017 shall be provided for each feeder within the service territory. Additionally, the baseline shall be provided with and without Excludable Major Events[11] (EME) along with a summary of the main causes of outages on each feeder. The metric will use the circuit three-year SAIDI covering the years 2015-2017 average as the baseline. It will compare the SAIDI results of the plan year to the circuit's 2015-2017 three-year historic average.

[11] The Department has defined an "Excludable Major Event" as a major interruption event that meets one of the three following criteria: (1) the event is caused by earthquake, fire or storm of sufficient intensity to give rise to a state of emergency proclaimed by the Governor (as provided under the Massachusetts Civil Defense Act); (2) any other event that causes an unplanned interruption of service to fifteen percent or more of an Electric Company's total customers in its entire service territory; or (3) the event was a result of the failure of another company's transmission or power supply system. D.P.U. 12-120-D, §I.B (2015). An interruption event caused by extreme temperature condition is not an Excludable Major Event. Id.

1.10.7 Results

The tables below summarize the 2020 CKAIDI metric results[12] for ADA and M&C circuits, respectively, as published in the Guidehouse PY 2020 Evaluation Reports. Results are given with and without excludable major events (EMEs) and the number of circuits included in the analysis are indicated.

2020 ADA Performance Metrics Summary: CKAIDI

	2015-2017 Avg. CKAIDI (Baseline)				2020 CKAIDI (Program Year)			
	System-wide[13]		ADA Circuits		System-wide		ADA Circuits	
	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs
Total Circuits	2,083	2,083	175	175	2,083	2,083	175	175
Weighted* Average	134	106	160	140	238	238	294	294

*Circuit reliability statistics were weighted based on customer counts.

Source: Guidehouse PY2020 ADA Evaluation Report, filed June 30th, 2021.

2020 M&C Performance Metrics Summary: CKAIDI

	2015-2017 Avg. CKAIDI (Baseline)				2020 CKAIDI (Program Year)			
	System-wide		M&C Circuits		System-wide		M&C Circuits	
	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs
Total Circuits	2,083	2,083	197	197	2,083	2,083	197	197
Weighted* Average	134	106	90	86	238	238	419	419

*Circuit reliability statistics were weighted based on customer counts.

Source: Guidehouse PY2020 M&C Evaluation Report, filed June 30th, 2021.

For PY2020, weighted average outage duration for circuits with ADA and/or M&C was significantly longer than Baseline. However, many factors impact outage duration including weather and storm activity, etc. The metric is not able to discern whether ADA and/or M&C investments impacted the outage duration. As noted in the PY 2020 Evaluation Reports for ADA and M&C, calendar year 2020 had a greater frequency and size of storms than normal, which may have contributed to longer average outage duration.

The tables below summarize the 2019 CKAIDI metric results for ADA and M&C circuits, respectively, as published in the Guidehouse PY 2019 Evaluation Reports.

[12] The 2020 results shown here are the latest available at the time of writing. Results from the 2021 program year will be available in the updated Grid Mod Evaluation reports in June, 2022.

[13] System-wide refers to all circuits in the GMP Annual Report Appendix 1 that had complete data.

2019 ADA Performance Metrics Summary: CKAIDI

Summary	2015-2017 Avg. CKAIDI (Baseline)				2019 CKAIDI (Program Year)			
	System-wide		Targeted for ADA through 2019		System-wide		ADA installed H1 2019 and Prior	
	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs
CKAIDI Statistics								
Total Circuits	2,085	2,085	171	171	2,085	2,085	60	60
% Zero	41%	34%	2%	2%	41%	44%	1%	6%
Average	80.0	63.3	162.9	143.4	169.2	75.5	208.1	117.9

Source: Guidehouse PY2019 ADA PM Addendum, filed June 30th, 2020.

2019 M&C Performance Metrics Summary: CKAIDI

Summary	2015-2017 Avg. CKAIDI (Baseline)				2019 CKAIDI (Program Year)			
	System-wide		Targeted for M&C through 2019		System-wide		M&C installed H1 2019 and Prior	
	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs
CKAIDI Statistics								
Total Circuits	2,085	2,085	133	133	2,085	2,085	68	68
% Zero	41%	34%	25%	25%	41%	44%	12%	13%
Average	80.0	63.3	72.4	68.5	169.2	75.5	185.0	107.8

Source: Guidehouse PY2019 M&C PM Addendum, filed June 30th, 2020.

For PY2019, average outage duration for circuits with M&C was longer than the Baseline, but ADA circuits showed improved performance over non-ADA circuits for non-EME events. Note that many factors impact outage duration including weather and storm activity, etc. The CKAIDI metric is not able to discern whether ADA and/or M&C investments impacted the outage duration or whether the results are due to other factors.

The Companies have proposed a stakeholder process to evaluate and modify, as needed, certain GMP metrics to ensure they are obtainable and informative. PY2021 results will be provided in June 2022.

1.11 Reliability-Focused Grid Modernization Investments' Effect on Outage Frequency

1.11.1 Type

Statewide Performance Metric

1.11.2 Objective

This metric will compare the experience of customers on DA-enabled circuits as compared to the prior three-year average for the same circuit. This metric will provide insight into how DA can reduce the frequency of outages.

1.11.3 Assumptions

Outages and their impact are typically situational in nature. The DA solutions must be capable of performing intended actions in under the one-minute threshold set by the Department. There may be circumstances where more complex FLISR schemes may take longer than one minute, but less than five, to properly locate, isolate and restore an impacted area safely. The circuit must have three years of System Average Interruption Frequency Index ("SAIFI") history to be included in the metric.

1.11.4 Calculation Approach

This metric will track and report on the following:

- Circuit level SAIFI for circuits that have DA enabled in the GMP plan year;
- Three-year average circuit level SAIFI covering the years 2015, 2016, and 2017; and
- Compare the current year circuit SAIFI with the three-year historic average SAIFI of that circuit.

AVERAGE ('CKAIFI 2015'+' CKAIFI 2016'+' CKAIFI 2017') - 'CKAIFI Year n' = if greater than 0, positive impact.

1.11.5 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

1.11.6 Baseline

The pre-investment baseline of a static three-year average circuit level SAIFI in 2015, 2016, and 2017 shall be provided for each feeder within the service territory. Additionally, the baseline shall be provided with and without Excludable Major Events along with a summary of the main causes of outages on each feeder. The metric will use the circuit three-year SAIFI average covering the years 2015-2017 as the baseline for this metric. It will compare the SAIFI results of the GMP plan year to the circuit's 2015-2017 three-year historic average.

1.11.7 Results

The tables below summarize the 2020 CKAIFI metric results[14] for ADA and M&C circuits, respectively, as published in the Guidehouse PY 2020 Evaluation Reports. Results are given with and without excludable major events (EMEs) and the number of circuits included in the analysis are indicated.

2020 ADA Performance Metrics Summary: CKAIFI

	2015-2017 Avg. CKAIFI (Baseline)				2020 CKAIFI (Program Year)			
	System-wide		ADA Circuits		System-wide		ADA Circuits	
	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs
Eversource								
Total Circuits	2,083	2,083	175	175	2,083	2,083	175	175
Weighted* Average	1.0	0.9	1.3	1.2	1.2	1.2	1.4	1.4

*Circuit reliability statistics were weighted based on customer counts.

Source: Guidehouse PY2020 ADA Evaluation Report, filed June 30th, 2021.

2020 M&C Performance Metrics Summary: CKAIFI

	2015-2017 Avg. CKAIFI (Baseline)				2020 CKAIFI (Program Year)			
	System-wide		M&C Circuits		System-wide		M&C Circuits	
	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs
Eversource								
Total Circuits	2,083	2,083	197	197	2,083	2,083	197	197
Weighted* Average	1.0	0.9	0.8	0.8	1.2	1.2	1.2	1.2

*Circuit reliability statistics were weighted based on customer counts.

Source: Guidehouse PY2020 M&C Evaluation Report, filed June 30th, 2021.

For PY2020, weighted average outage frequency for circuits with ADA and/or M&C was higher than the Baseline. However, many factors impact outage frequency including weather and storm activity, etc. The metric is not able to discern whether ADA and/or M&C investments impacted the outage frequency. As noted in the PY 2020 Evaluation Reports for ADA and M&C, calendar year 2020 had a greater frequency and size of storms than normal, which may have contributed to higher average outage frequency.

The tables below summarize the 2019 CKAIFI metric results for ADA and M&C circuits, respectively, as published in the Guidehouse PY 2019 Evaluation Reports.

[14] The 2020 results shown here are the latest available at the time of writing. Results from the 2021 program year will be available in the updated Grid Mod Evaluation reports in June, 2022.

2019 ADA Performance Metrics Summary: CKAIFI

Summary	2015-2017 Avg. CKAIFI (Baseline)				2019 CKAIFI (Program Year)			
	System-wide		Targeted for ADA through 2019		System-wide		ADA installed H1 2019 and Prior	
	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs
CKAIFI Statistics								
Total Circuits	2,085	2,085	171	171	2,085	2,085	60	60
% Zero	34%	34%	2%	2%	41%	45%	1%	6%
Average	0.5	0.5	1.2	1.2	0.8	0.5	1.1	0.7

Source: Guidehouse PY2019 ADA PM Addendum, filed June [30th], 2020.

2019 M&C Performance Metrics Summary: CKAIFI

Summary	2015-2017 Avg. CKAIFI (Baseline)				2019 CKAIFI (Program Year)			
	System-wide		Targeted for M&C through 2019		System-wide		M&C installed H1 2019 and Prior	
	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs	w/ EMEs	w/o EMEs
CKAIFI Statistics								
Total Circuits	2,085	2,085	133	133	2,085	2,085	68	68
% Zero	34%	34%	25%	25%	41%	45%	12%	13%
Average	0.5	0.5	0.6	0.6	0.8	0.5	1.1	0.9

Source: Guidehouse PY2019 M&C PM Addendum, filed June 30th, 2020.

For PY2019, average outage frequency for circuits with ADA was lower than the baseline outage frequency on the same circuits, but M&C outage frequency was higher than the baseline on the same circuits. Many factors impact outage frequency including weather and storm activity, etc. The CKAIFI metric is not able to discern whether ADA and/or M&C investments impacted the outage frequency or whether the results were due to other factors.

1.12 VVO Related Voltage Complaints Performance Metric and Baseline

1.12.1 Type of Metric

Statewide Performance Metric

1.12.2 Objective

The primary focus of the VVO investments is to manage circuit voltages at a lower threshold while maintaining minimum voltage service requirements for all customers on a substation and circuit. Since VVO will be actively managing voltages, there is a desire to track and report on the potential for the introduction of VVO-related voltage complaints. While VVO is not an active solution in use by the Companies today in Massachusetts, there may be historical low voltage causes that exist outside of a customer's service connection and equipment. Certain voltage issues, such as those that are ultimately determined to have been caused by customer-owned equipment, will not be mitigated by the Companies' VVO investments. The Companies will measure the change in voltage complaints following deployment of VVO technology to determine the impact relative to a pre-deployment baseline.

1.12.3 Assumptions

Prior to the requirement to track and report on whether VVO investments could potentially contribute to customer voltage complaints, there was never a need for the Companies to track customer voltage complaints in this manner. For instance, in some cases large commercial and industrial ("C&I") customers' voltage complaints were processed through their customer account executives and were not necessarily logged in the Companies' work management systems: thus, there is no data as to the cause of the voltage issue that gave rise to the complaint. While residential customer voltage complaints were logged in the respective systems, given that VVO is a new investment the Companies cannot reasonably associate these historical complaints as being caused or impacted by VVO investments. In an effort to develop a baseline for this metric, the Companies must manually review the available records to determine the cause and remedy of the voltage issue that led to the customer complaint.

Going forward, the Companies intend to specifically track customer voltage complaints to determine if VVO investments led to the voltage condition giving rise to the customer complaint. Eversource currently has a tracking and reporting process in its Western Massachusetts ("WMA") and Eastern Massachusetts ("EMA") service territory that enables it to capture and categorize the necessary data related to these voltage complaints. Eversource expanded this process into its Eastern Massachusetts ("EMA") service territory to ensure that all relevant data related to the impact of VVO investments on customer voltage complaints is tracked and reported. Unitil currently tracks customer voltage complaints in its Customer Information System ("CIS") and plans to revise the system coding to better capture the data necessary to determine if a voltage issue was impacted by VVO investments. National Grid is currently exploring system and process improvements and enhancements to ensure it is able to track the necessary data on these customer complaints.

Given the lack of consistent and comprehensive data as to whether a customer's voltage complaint was influenced by VVO investments, the Companies propose to utilize all customer voltage complaints received in 2015, 2016 and 2017 to develop the baseline for this performance metric. Additionally, since the compilation of the voltage complaints is a significant manual process, the Companies propose, for the 2018-2020 GMPs, to utilize the following circuits to establish the initial baseline for this performance metric.

Eversource – In its 2018-2020 GMP, Eversource will deploy VVO on circuits in WMA. As previously mentioned, there was a voltage complaint tracking system in WMA so Eversource will establish a baseline based on the information included in the WMA tracking system and report on the WMA performance. There are no VVO investments planned in EMA during 2018-2020. Eversource will incorporate EMA in its baseline, tracking and reporting process in 2021 for the next three-year GMP (2022-2024).

Unitil – Under its approved GMP, Unitil intends to install VVO investments on all of the circuits in its service territory. For this performance metric, Unitil proposes to utilize all of its circuits in establishing the baseline.

National Grid – National Grid proposes, as an initial baseline, to use the 16 feeders on which it intends to install VVO investments under its 2018-2021 GMP. National Grid is targeting larger circuits in its service territory, that serve approximately 1000 customers or more. National Grid will, following its development and implementation of system and process improvements and enhancements to track these customer complaints and the relevant data, incorporate the remainder of the circuits in its service territory into the baseline for this performance metric for the 2021-2023 GMP

Eversource and National Grid propose to update the baseline for this metric with respect to the 2022-2024 GMPs to include all circuits within their respective service territories.

1.12.4 Calculation Approach

This metric will track and report on the following:

- Quantity of voltage complaints for the current year that are deemed caused by VVO voltage management by circuit for circuits that will have VVO installed.
- Three-year average of all voltage complaints by circuit covering the years 2015, 2016, and 2017.
- Compare the current year quantity of voltage complaints with the three-year historic average.

AVERAGE ('Voltage Complaints 2015'+ 'Voltage Complaints 2016' + 'Voltage Complaints 2017') = Voltage Complaint Baseline

1.12.5 Organization of Result

The baseline voltage complaints and the annual VVO-related voltage complaints (once VVO investments are active and enabled) will be provided on an annual basis for each circuit. Results will be based upon the results at the end of the calendar year. This will provide the Department an opportunity to assess the effectiveness of the VVO investments while minimizing the introduction of new customer impact.

1.12.6 Baseline

Utilizing the assumptions discussed above, the Companies will calculate the 2015 through 2017 baseline to use to measure process under this metric. Given the manual and time-consuming nature of the process to review and compile the customer complaint data, the Companies have determined that this process can be undertaken and completed by June 28, 2019 for incorporation into the Companies' respective 2018 Annual Grid Modernization Reports.

1.12.7 Results

The baseline calculated for this metric was 318 voltage complaints across WMA circuits. At the end of 2021, the Company recorded 439 voltage complaints related to WMA circuits. This represents an increase of 121 voltage complaints over the baseline period for the WMA region. On VVO circuits, the Company recorded a baseline of 49 voltage complaints. At the end of 2021, the Company recorded 76 voltage complaints on VVO circuits. This represents an increase of 27 voltage complaints over the baseline period.

The Company also built a process for tracking EMA-related voltage complaints. The Company will utilize this tracking system for EMA going forward. The circuit level detail for voltage complaints can be found in the Appendix 1 attachment.

It is important to note two items: 1) frequently, voltage complaints are not caused by the electric distribution system but are instead driven by customer-owned equipment; and 2) it would be very difficult to correlate whether voltage complaints increased or decreased due to the VVO system. Voltage complaints are generally associated with the nearest upstream isolating devices. Due to the customer driven nature of voltage complaints, the associated devices are not typically SCADA enabled (i.e., distribution transformer or lateral fuses). Correlating the operations of VVO specific devices while VVO is in an enabled operating state to these non-SCADA devices and customer complaints is an extremely difficult and time-consuming effort that has yet to provide significant findings.

1.13 Eversource Advanced Load Flow – Percent Milestone Completion

1.13.1 Type of Metric

Eversource-specific Performance Metric

1.13.2 Objective

The metric is designed to demonstrate progress towards the final completion of a fully automated modelling tool. The metric will measure percent completion relative to a final deliverable of a fully automated load flow tool used by Eversource engineers and system operators to perform multi-circuit analysis for all non-network circuits.

1.13.3 Assumptions

Demonstration of progress will be measured by assessment of achieved functionality. Models and capabilities will continue to improve in functionality and accuracy with further refinements in a process of continuous improvement of modeling tools.

1.13.4 Calculation Approach

Under this metric, the percent completion will be determined based on the demonstrated progress with respect to the following milestone targets:

Static Analysis: Ability to analyze results at an individual circuit level - for new load, for Distributed Generation ("DG") pre-application screening, fault analysis, high/low voltage complaint investigations.

Semi-Automatic 1: Ability to run basic analysis in an automated process at an individual circuit level – for new load, DG pre-application screening, fault analysis, high/low voltage complaint investigations.

Semi-Automatic 2: Added capability to automatically run processes on groups of circuits – advanced DG impact studies, including contingencies and alternate source analysis.

Fully Automated: Capability to automatically run processes on all circuits, storing results in a database that can be used by engineering and operations, as well as for customer facing information tools like hosting capacity maps.

1.13.5 Organization of Results

Results will be organized by percent of feeders meeting each milestone target.

1.13.6 Baseline

The baseline is estimated at 40 percent of circuits meeting the Static Automation milestone and 10 percent of feeders meeting the Semi-Automatic 1 metric. Baseline for Static Automation 2 and Fully Automated are each 0 percent.

1.13.7 Results

At the end of the 2018-2021 term the Eversource Advanced Load Flow percent milestone complete was 100% fully automated.

1.14 Eversource Customer Outage Metric

1.14.1 Type of Metric

Eversource-specific Performance Metric

1.14.2 Objective

This metric is intended to measure progress in sectionalizing circuits into protective zones designed to limit outages to customers located within the zone. This metric will measure progress in achieving the grid modernization objective of reducing the impact of outages.

1.14.3 Assumptions

A protective zone is defined as the portion of a circuit or circuits that would be isolated by automated backbone devices that will operate automatically to minimize the number of customers affected in the event of an outage.

1.14.4 Calculation Approach

For each circuit and for the sum of circuits in EMA and WMA, the metric will track and report on the average zone size in terms of number of customers interconnected in each protective zone.

1.14.5 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

1.14.6 Baseline

The Company will provide the average zone size by circuit as of the end of 2017 as the baseline for this metric.

1.14.7 Results

The average circuit zone size baseline calculated in 2018 prior to any GMP device deployment was 359 customers. During the 2018-2021 period, the average circuit zone size decreased to 285 customers. This represents a reduction of 74 customers. The circuit level details can be found in the Appendix 1 attachment.

D. Lessons Learned/Challenges and Successes

M&C and ADA investments are yielding reliability and service delivery benefits to customers, as shown by case studies in the evaluation reports completed by Guidehouse. The case studies show detailed functioning and impact of GMP devices, often quantifying the avoided interruption duration and customer counts. Case studies are proving to be a useful tool in understanding the effectiveness of the M&C and ADA investments.

In evaluating M&C and ADA investments, the CKAIDI and CKAIFI reliability-related Performance Metrics as defined have been shown to have deficiencies in measuring the effectiveness of Grid Modernization Investments. Many factors unrelated to the Grid Modernization investments will affect these metrics in any given year, and it is not possible to distinguish among these factors using the metrics. For example, the variation in weather, such as storm activity and heat waves, between years can cause significant changes in these metrics. Also, the need for three years of baseline data excludes circuits that have been reconfigured over time, reducing the pool of circuits that can be compared to a baseline value. 2021 performance metrics will be reported in June 2022.

The VVO investments included many of the established performance metrics. One of the benefits of the on / off testing methodology for VVO is the ability to calculate preliminary results without a full year of measured data. As described above, VVO data analysis during Eversource's first season of VVO on / off testing spanning winter 2020/21 indicated a reduction in energy usage of 853 MWh, or 0.75 percent. Coupled with evaluated voltage reductions, the VVO CVR factor – an indicator of energy savings possible for each percent reduction in voltage – was 0.82 for the winter 2020/21 season. As a result of energy reductions observed during the on / off testing period, VVO resulted in a 422 short ton reduction in CO_2 emissions. A 422 short ton reduction in CO_2 is comparable to the emissions of 90.9 gasoline-powered passenger vehicles driven for one year.

Although most of the VVO metrics, inclusive of on / off testing methodology, have proven successful in M&V of the program, the Company, in collaboration with Guidehouse and the other Distribution Companies, has proposed revisions to several metrics to improve the quality of the analysis and results. The original VVO metrics were developed prior to engagement by

Guidehouse or before the system was fully deployed and operational. The revised VVO performance metrics were amended to resemble the methods Guidehouse utilized in their evaluation. For instance:

- Increasing the duration of the VVO on/off testing was appropriate in order to encompass the seasonal variations in load profiles.
- Clarifying language in order to maintain consistency.
- Updating the baseline to reflect the “off” period of the on/off testing, as opposed to using a prior-to-deployment three-year average baseline.
- The reference to collecting sub-one-hour intervals of data.
- Calculation changes to peak load reduction.

The aforementioned changes were incorporated into the Company’s July 1, 2021 filing for GMP 2022-2025 (D.P.U. 21-80, Exhibit ES-JAS-2 Attachment A). These changes were incorporated for the following reasons:

- The existing guidance for VVO on/off testing recommended conducting on/off testing for three to six months. However, there is seasonal variation in load profiles and nine months enables incorporating a summer and winter season plus a spring and/or fall season to better approximate the impact of VVO across a year.
- Update VVO metric descriptions to align with the updated methodology across performance metrics.
- The new baseline references the “off” period during VVO on/off testing. A VVO on/off testing procedure seeks to have similar temperature, day of week, time of day collected in the treatment (“On”) and control (“Off”) states and is an industry standard approach. Evaluation of performance metrics using data collected during the period prior to VVO deployment as a baseline can lead to inaccurate estimates of VVO performance. Some reasons include:

    - EDC sensors installed at the circuit head-end can be replaced as VVO is being deployed. The EDCs have observed a difference in data values recorded by new head-end sensors and decommissioned head-end sensors at the same point in time. Evaluation results derived by comparing the differences between pre-VVO and post-VVO data will therefore be compromised by underlying differences between measurements collected by new head-end sensors and decommissioned head-end sensors.
    - EDCs have observed significant growth in distributed solar throughout the course of VVO deployment. This can affect voltage, demand, and power factor for each VVO circuit. VVO evaluation results derived by comparing the differences between

pre-VVO and post-VVO data may reflect changes to voltage, demand, and power factor, which could be attributed to increased distributed solar penetration.

- EDCs may shift customer loads across circuits over time due to feeder reconfiguration or customer load composition changes. VVO evaluation results derived by comparing the differences between pre-VVO and post-VVO data may inadvertently include load shifting.
- The year prior to VVO/CVR deployment may not be a representative meteorological year. VVO evaluation results derived by comparing the differences between pre-VVO and post-VVO data will affected by underlying differences in weather conditions observed prior to VVO deployment and after VVO deployment, which impact voltage, demand, and power factor.

- Sub-one-hour intervals of data are available for the EDCs and can detect more granular changes in energy, for instance, than hourly data. The existing language surrounding VVO Peak Load Impact denoted circuit-level M&V would provide a demand reduction estimate for each peak hour. Language was clarified to denote circuit-level M&V would provide an average hourly demand reduction across peak hours (1 p.m. to 5 p.m. on non-holiday weekdays spanning June 1 through August 31), not a demand reduction for a single peak hour, which may include customer participation in demand reduction activities.

V. Term Summary of Research, Design, and Development

In D.P.U. 12-76-B, the Department directed the Distribution Companies, as part of their GMPs, to propose research, design, and development ("RD&D") projects that focus on the testing, piloting, and deployment of new and emerging technologies to meet their grid modernization objectives. D.P.U. 12-76-B at 27-30. As part of its 2018-2020 GMP, Eversource filed an RD&D proposal to undertake projects in the following areas: (1) sensing and monitoring; (2) advanced analytics; (3) real-time flexible action and dynamic integration of distributed energy resources; (4) impact of grid modernization technologies on low-income customers; (5) pricing options; (6) customer engagement and behavioral response; and (7) microgrids. D.P.U. 15-122, at 44.

Ultimately, the Department did not approve the Company's proposed RD&D projects, nor did it approve the proposals filed by National Grid and Unitil. Id. at 185. The Department indicated that any future RD&D proposals incorporated into future GMPs would be reviewed consistent with the standards developed by the Department in light of RD&D proposals made in other contexts. Id. at 185, citing D.P.U. 17-05, at 457-460; NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 16-178, at 26, 29-30 (2017); Fitchburg Gas and Electric Light Company, D.P.U. 16-184, at 11 (2017). In reaching its decision, the Department emphasized that any RD&D proposals contained in future GMPs should be the result of collaboration between the Distribution Companies and other stakeholders. Id.

Consistent with the Department's decision in D.P.U. 15-122, the Company did not undertake any RD&D efforts as part of its 2018-2021 GMP. The Company will, in developing any future RD&D proposals, collaborate with National Grid and Unitil, as well as relevant stakeholders, prior to filing any proposal with the Department for its review and approval.

Massachusetts
Electric Vehicle Infrastructure Program

Charging Station Analysis Report
2021

Prepared by:

Clean Energy Consulting

3/15/2022

Electric Vehicle Infrastructure Program

On November 30, 2017, the Department of Public Utilities issued Order 17-05, approving NSTAR ELECTRIC COMPANY AND WESTERN MASSACHUSETTS ELECTRIC COMPANY d.b.a. Eversource Energy (Eversource) to spend up to $45 million over five years on an electric vehicle (EV) infrastructure program (Program).

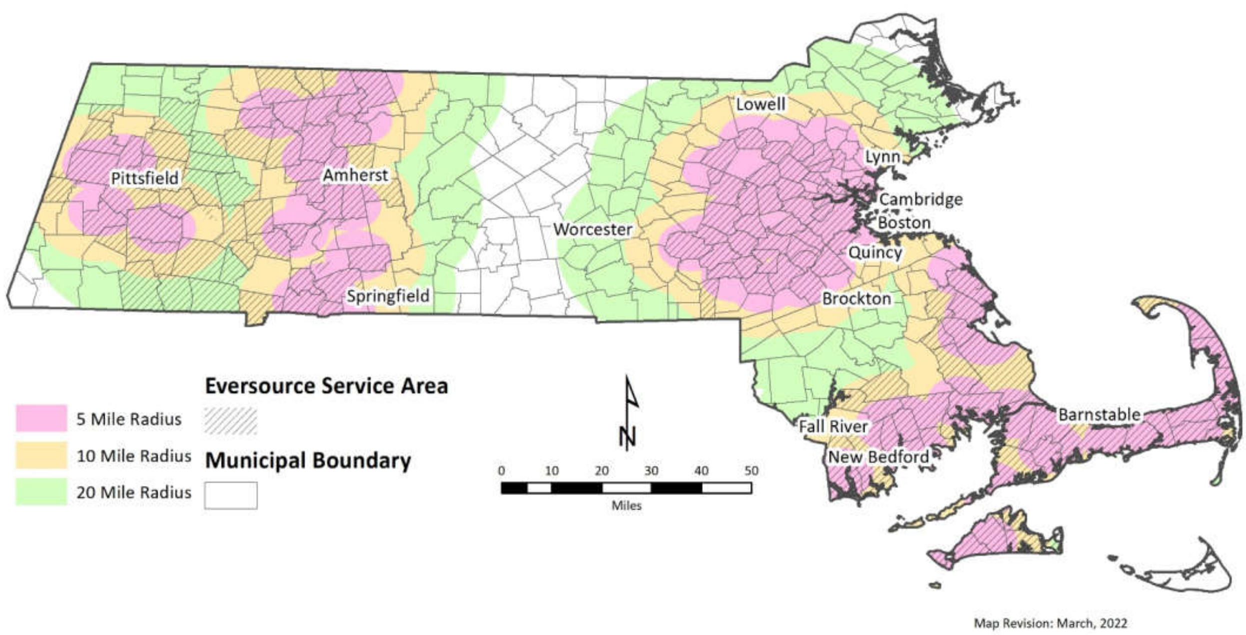
Eversource is supporting the deployment of EV charging ports by installing electrical equipment and components necessary to connect EV chargers to its distribution system. Eversource is installing the "Eversource-side Infrastructure," and contracting with third-party electrical contractors to install behind the meter "Participant-side Infrastructure." Specifically, the EV infrastructure that Eversource installs and owns includes: (1) distribution primary lateral service feed; (2) necessary transformer and transformer pad; (3) new service meter; (4) new service panel; and (5) associated conduit and conductor necessary to connect each piece of equipment.

Between 2018 and 2022, Eversource plans to support the deployment of up to 72 direct current fast charging (DCFC) ports at 36 sites, and up to 3,500 Level 2 charging ports at 450 sites, throughout its service territories in Massachusetts. Eversource hopes to accelerate implementation of the Make-Ready Program based on customer demand.

Eversource Customers Served by Program Installations

100% of Eversource customers are within 20 miles of a Program charging station

100% of Massachusetts residents and businesses are within 40 miles of a Program charging station

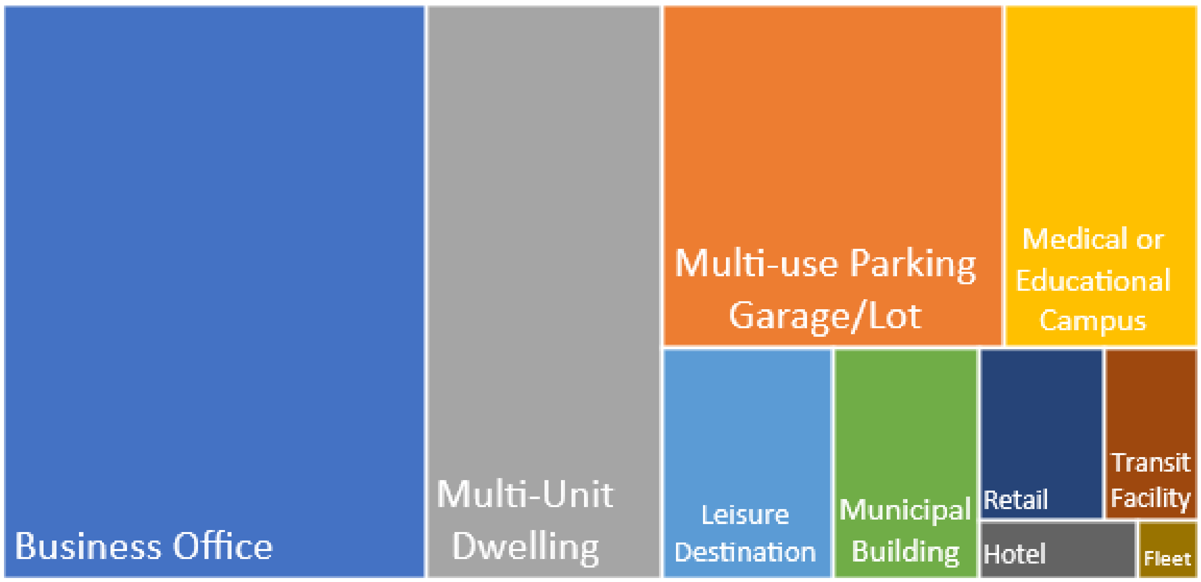


* 5-mile and 10-mile buffers surrounding Program charging stations are shown for reference.

Program Station Installations

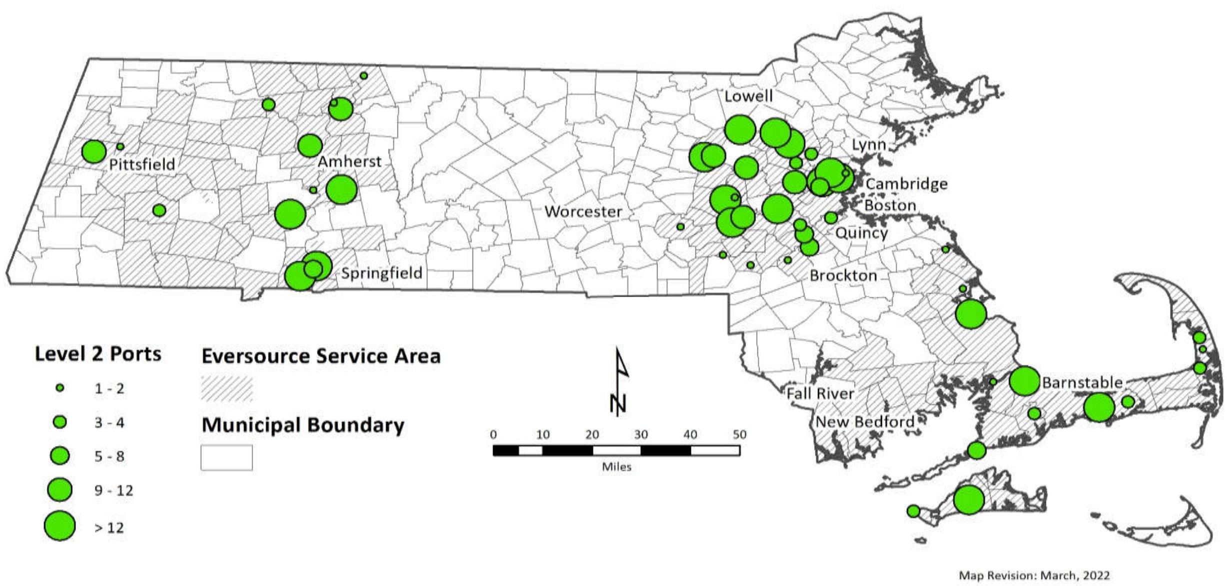
1,195 Level 2 Ports Installed by the Program to Date

Level 2 stations provide approximately 20 miles of electric driving range for each hour of charging.



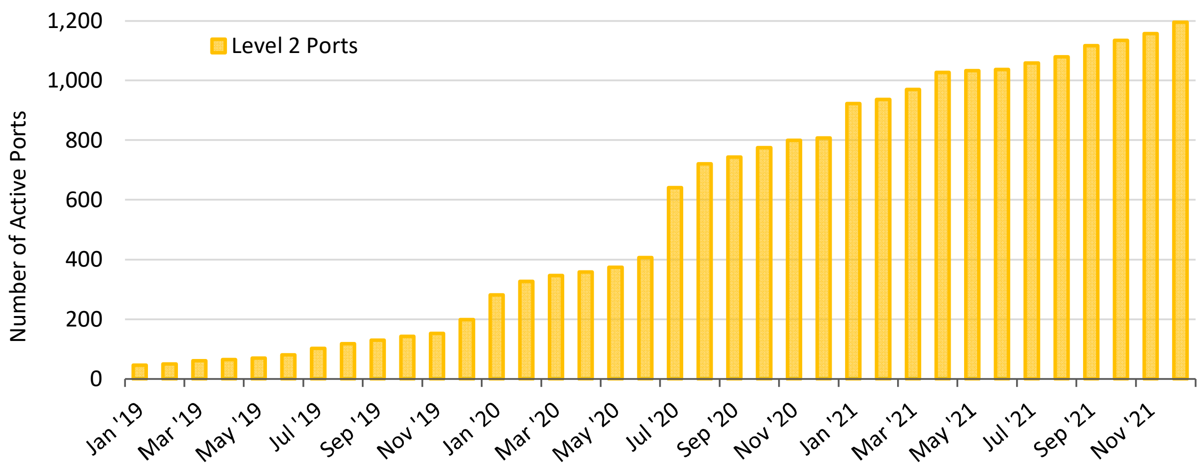
0 DCFC Ports Installed by the Program to Date

DCFC stations provide 50-150 miles of electric range in 20 minutes of charging.

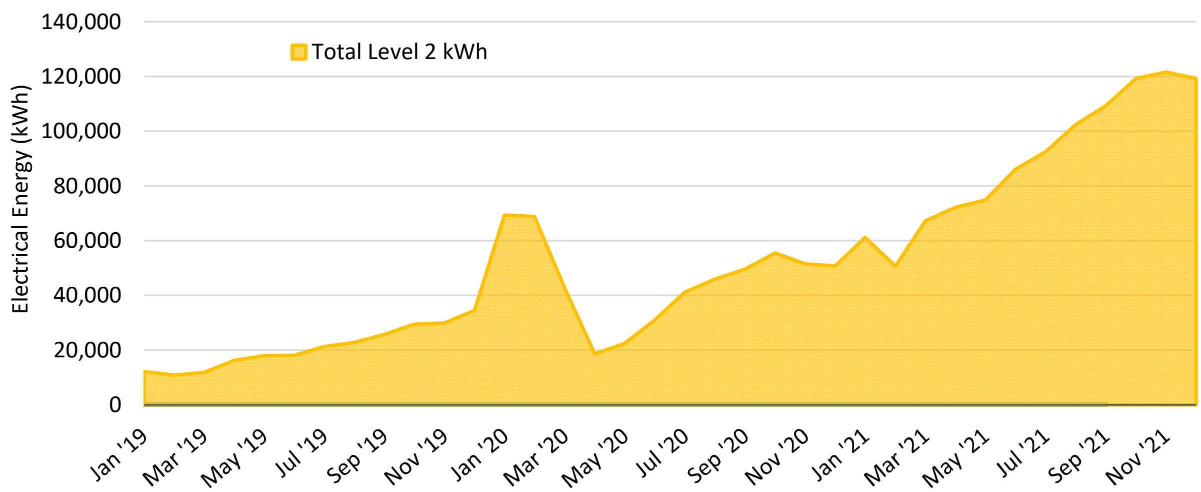


Program Station Installations

Ports are "Active" based on activation date provided by the service provider, excluding known periods when repairs were needed.



Energy Dispensed



Environmental Impacts		**2019**	**2020**	**2021**	**Program to Date**
Total Charging Events[1]	Level 2	19,988	44,123	85,242	149,353
	DCFC	0		0	0
	Total	**19,988**	**44,123**	**85,242**	**149,353**
Total Energy Dispensed (kWh)	Level 2	250,588	547,184	1,076,307	1,874,078
	DCFC	0	0	0	0
	Total	**250,588**	**547,184**	**1,076,307**	**1,874,078**
Gallons of Gasoline Displaced[2]		**37,457**	**81,791**	**160,883**	**280,131**
Tons of Carbon Dioxide Saved[3]		**264**	**577**	**1,134**	**1,975**

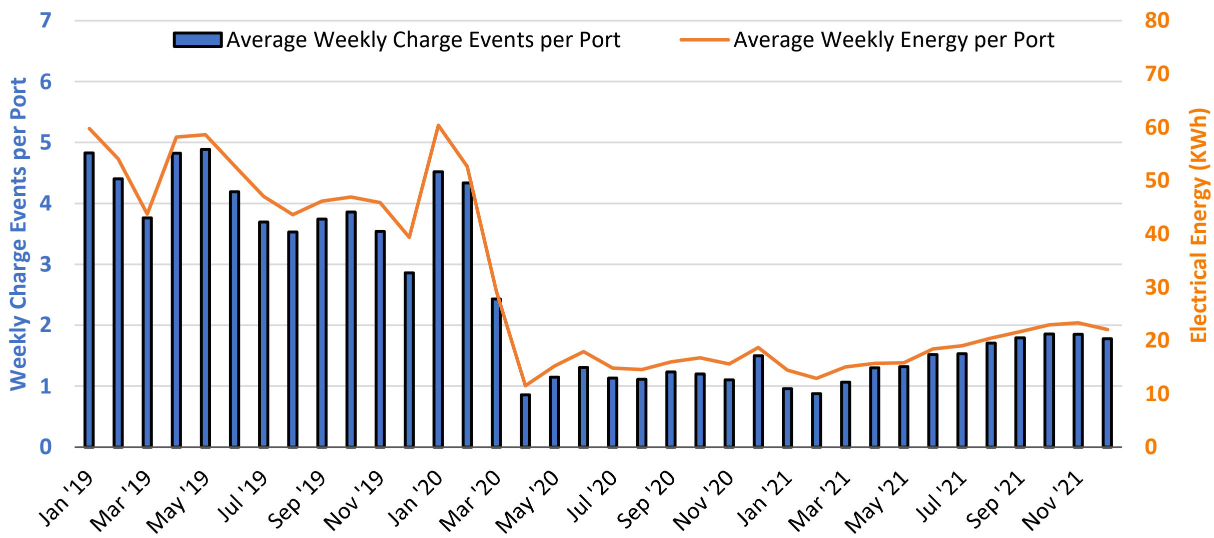
[1] A recorded event is classified as a charging event if at least 0.2 kilowatt-hours (kWh) is dispensed.

[2] Average EV efficiency = 0.3 kWh/mile (Plug In America). Average U.S. light duty vehicle fuel efficiency (2017) = 22.3 mpg (USDOT)

[3] CO_2 emmissions/gallon = 19.6 pounds. MA output emmission rate = 821 lb/MWh (USEPA)

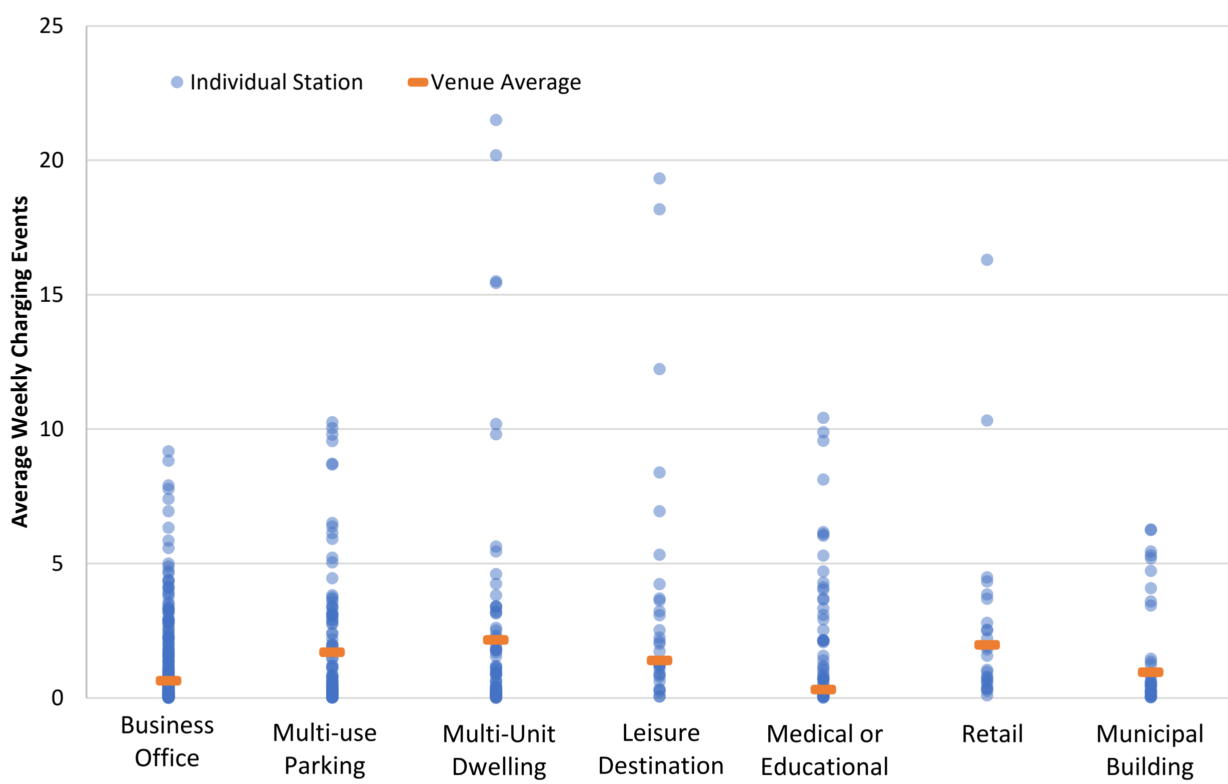
Level 2 Port Utilization

Average station utilization has begun to rebound since a dramatic decline in March 2020.



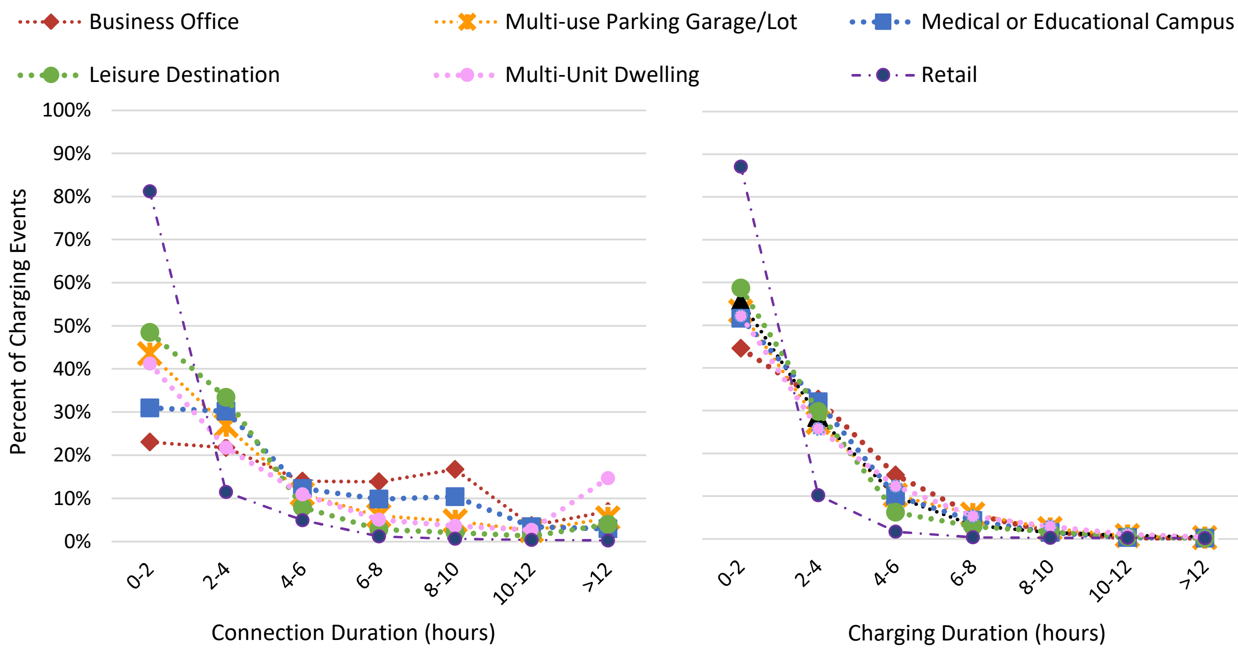
Level 2 Weekly Charging Events by Venue Type

Stations at Multi-use Parking Garages/Lots and Retail locations experienced the broadest range of utilization. Business Office and Medical/Educational campus chargers experienced the fewest average charge events per week compared to other venues. *



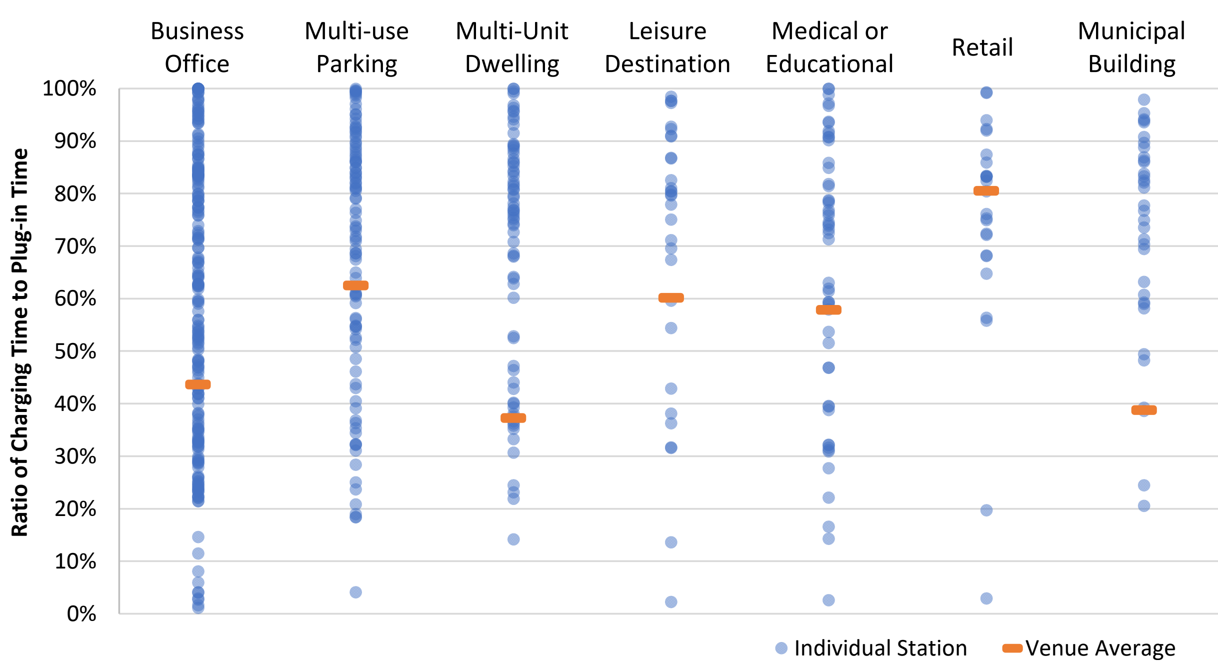
Durations for Level 2 Charging Events

Stations at Multi-unit Dwellings experienced more charge events with longer plug-in times (>12 hours). Business Offices and Medical/Educational Campuses show slight bumps at 6-8 and 8-10 hours. Charge sessions at Retail venues were shorter in duration compared to all other venues.



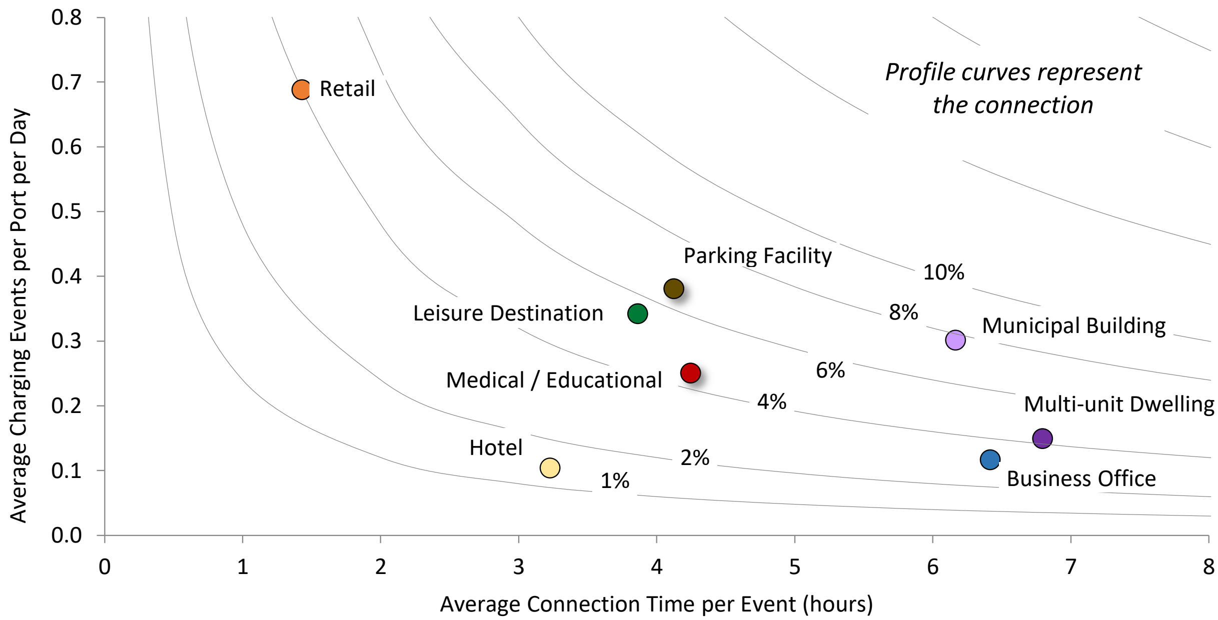
Connection Time Spent Charging for Level 2 Charging Ports

EVs often remained plugged in at Multi-unit Dwellings and Municipal Buildings considerably longer than their charging time (charging slightly less than 40% of the time). EVs charging at Retail venues spend the greatest amount of connection time drawing power (just over 80%, on average).



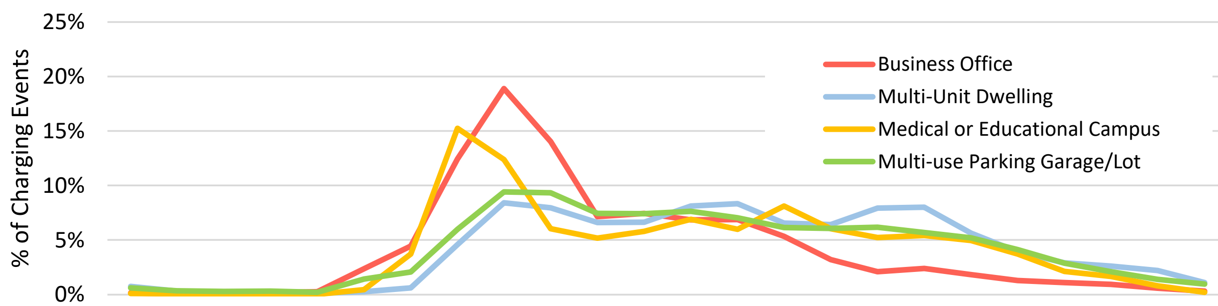
Level 2 Charging Characteristics by Venue Type

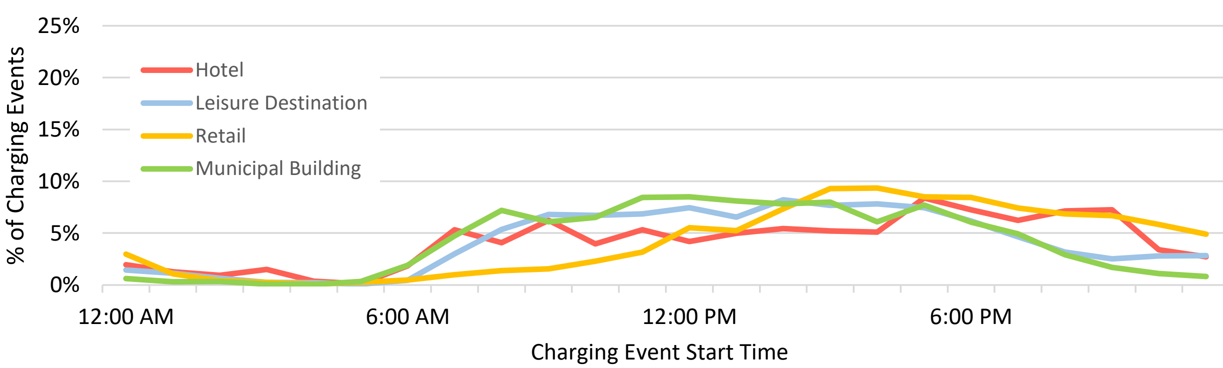
The average connection time plotted against the average number of daily charging events shows utilization characteristic differences by venue. Stations at municipal buildings had the highest utilization. Multi-Unit Dwellings and Business Offices had fewer but longer charging events. Retail venues had more but shorter charging events.



Level 2 Charging Event Start Times

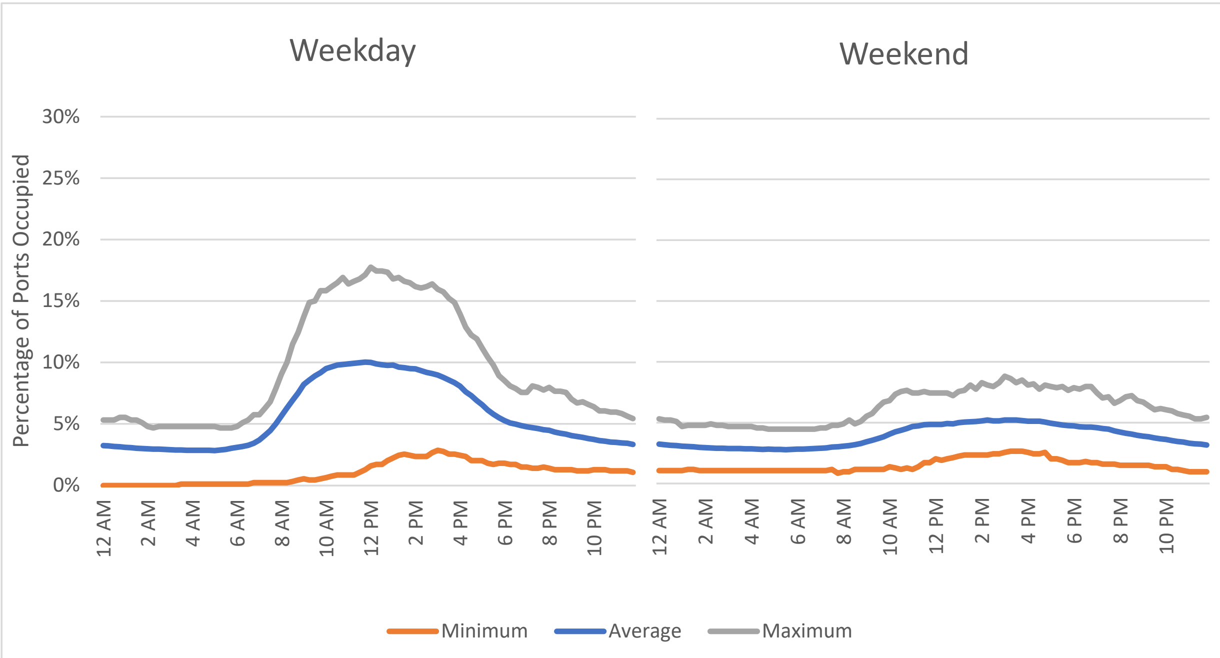
A large portion of charging events at Business Offices and Medical/Educational Campuses start earlier in the day, around 7-9 am. Other venues experience flatter distributions.



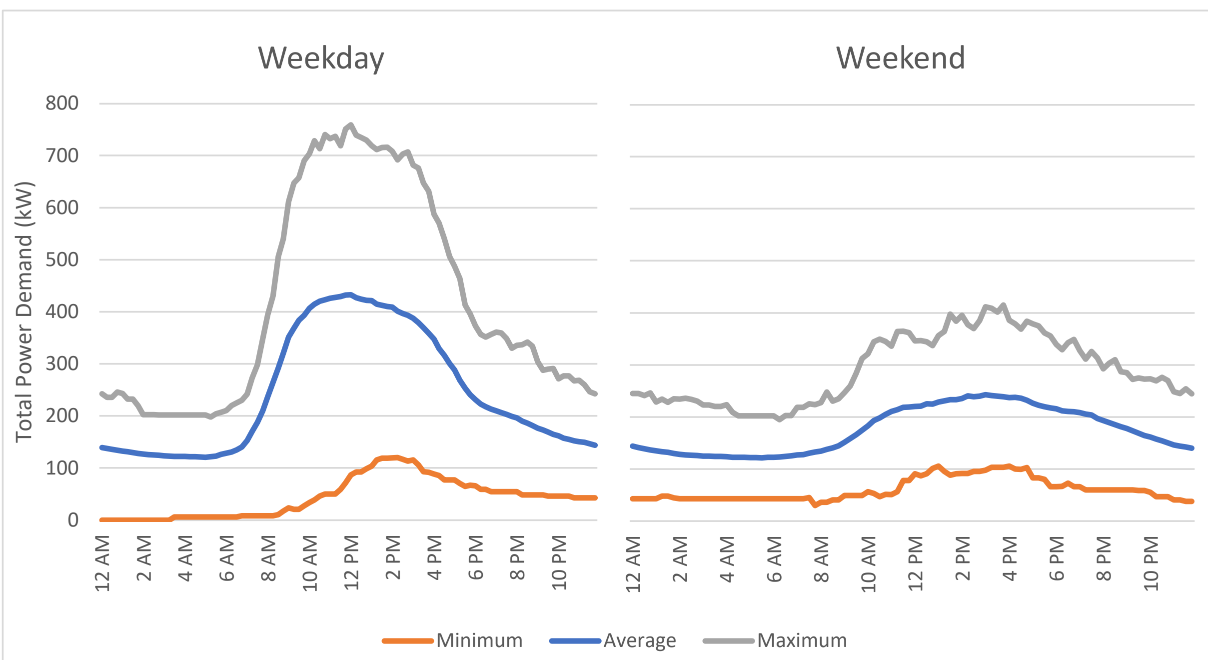


Level 2 Charging Impact on Power Grid - All Venues

Port Availability: Percentage of active charging ports in use across the time of day for weekdays and weekends. Peak occupancy is higher and earlier in the day on weekdays than on weekends.

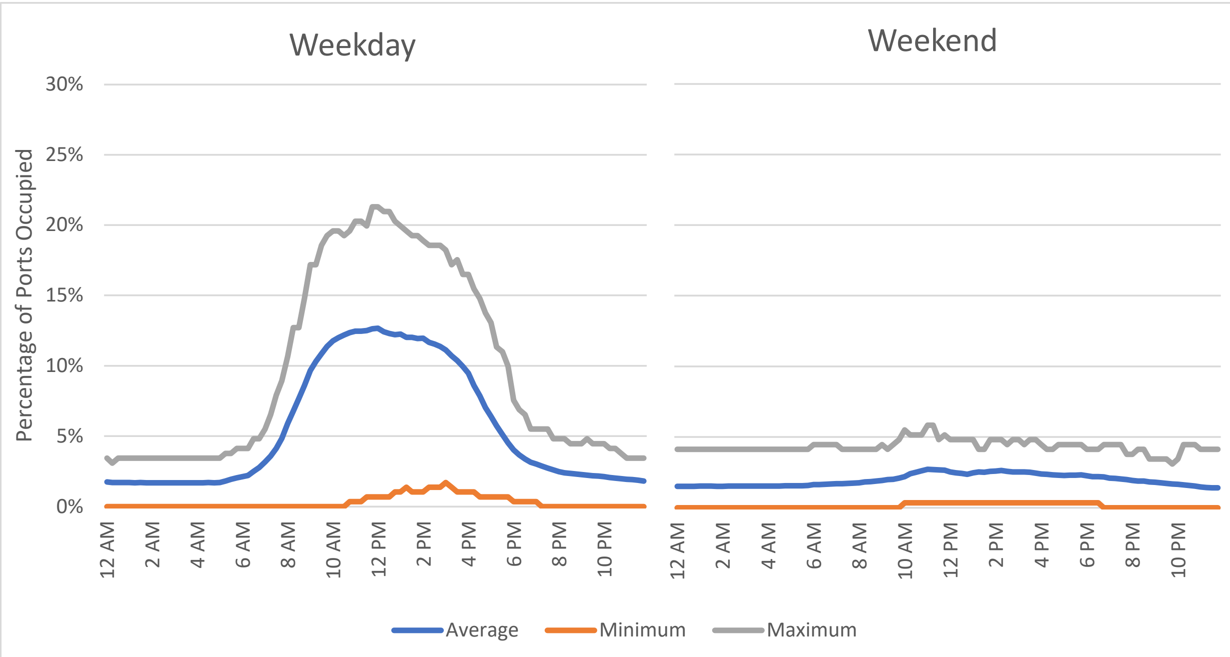


Estimated Total Charging Demand: Total power draw (calculated using average power per charging event for the charging duration) from all stations for weekdays and weekends. Weekday peak is around 12:00pm. There is a slight peak around 3:00pm on weekends.

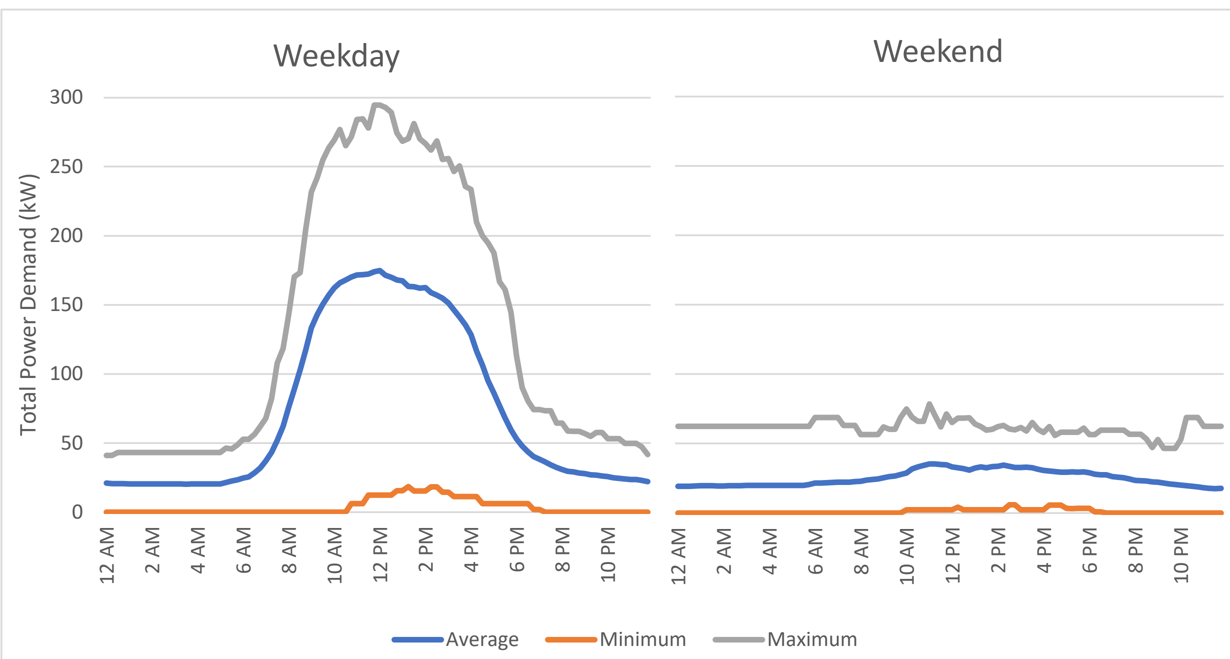


Level 2 Charging Impact on Power Grid - Business Office

Port Availability: Percentage of active charging ports in use across the time of day for weekdays and weekends.

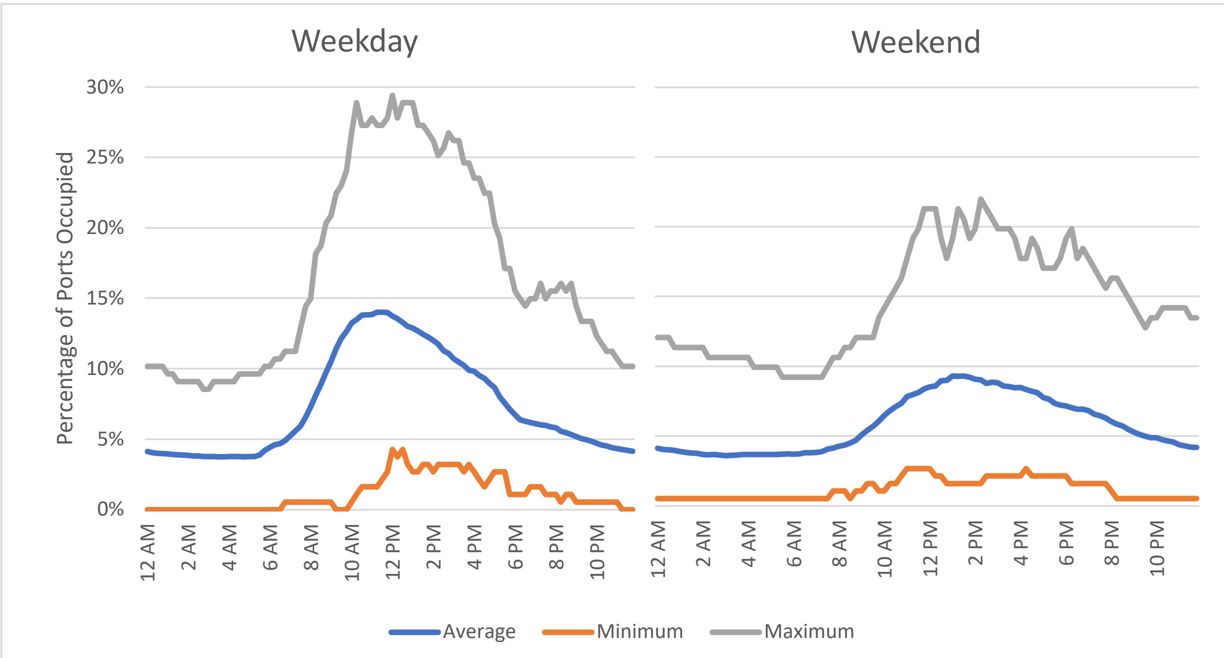


Estimated Total Charging Demand: Total power draw (calculated using average power per charging event for the charging duration) for weekdays and weekends.

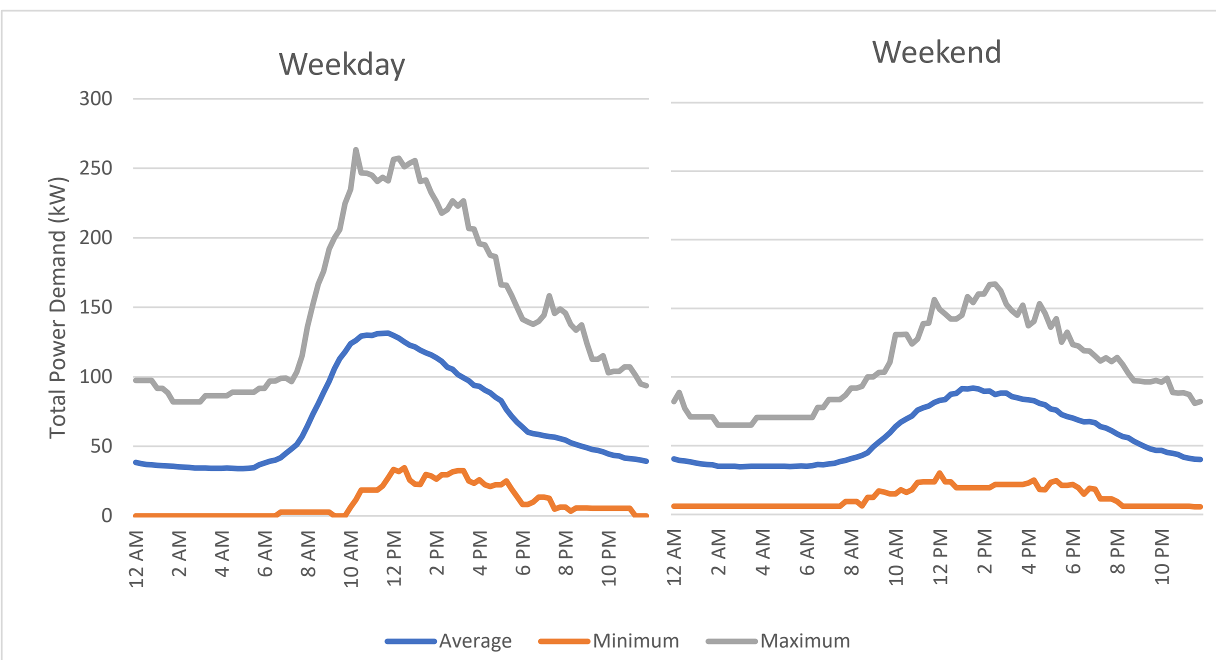


Level 2 Charging Impact on Power Grid - Parking Facility

Port Availability: Percentage of active charging ports in use across the time of day for weekdays and weekends.

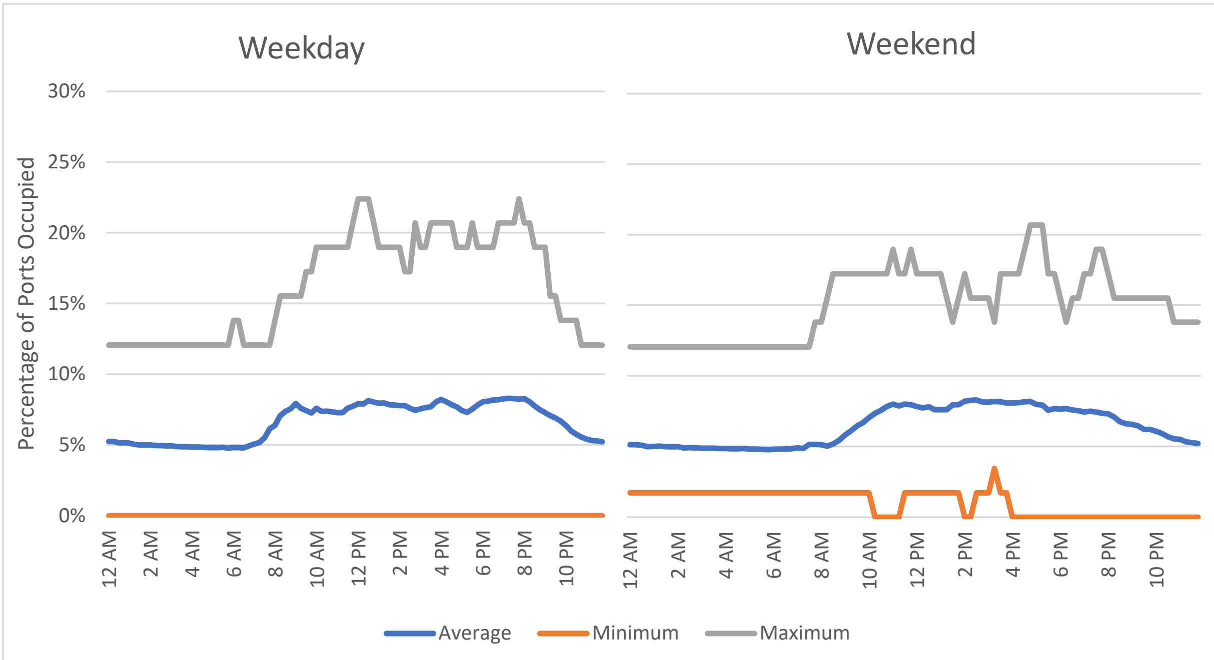


Estimated Total Charging Demand: Total power draw (calculated using average power per charging event for the charging duration) on weekdays and weekends.

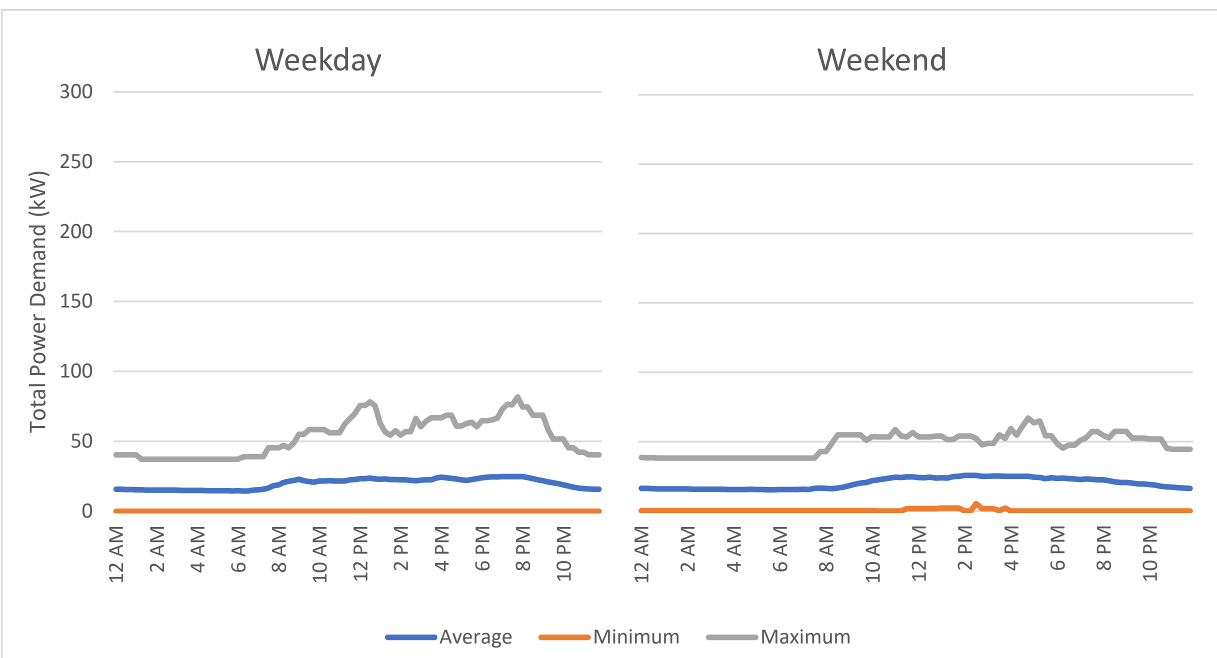


Level 2 Charging Impact on Power Grid - Municipal Building

Port Availability: Percentage of active charging ports in use across the time of day for weekdays and weekends.

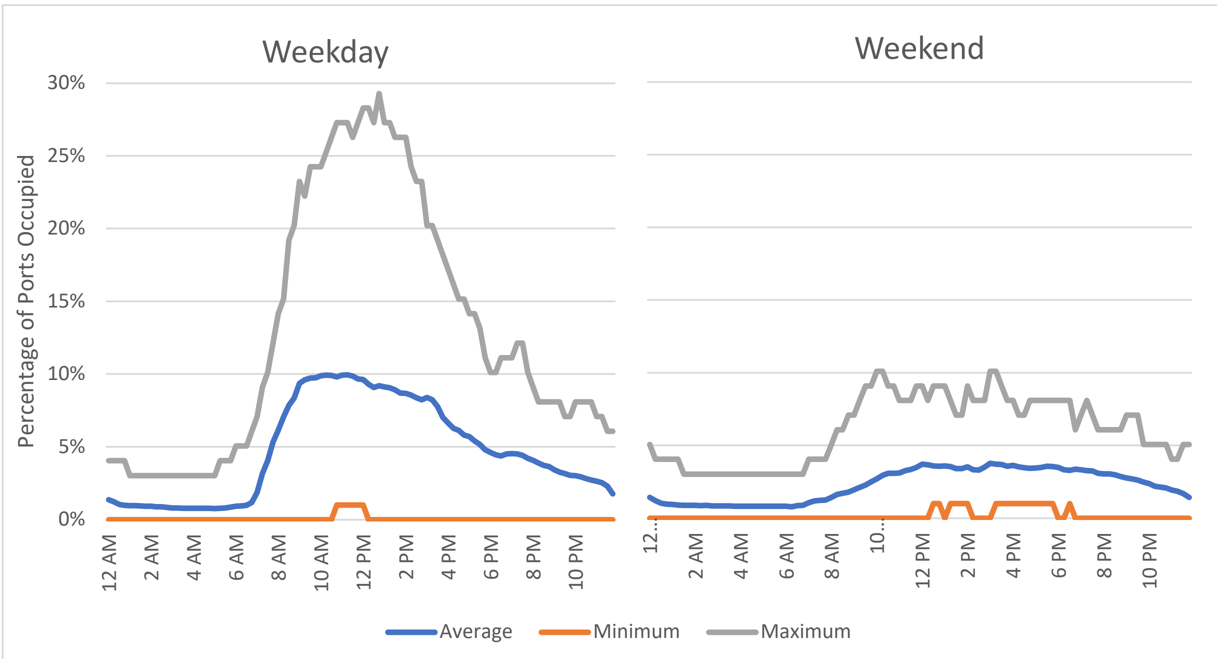


Estimated Total Charging Demand: Total power draw (calculated using average power per charging event for the charging duration) for weekdays and weekends.

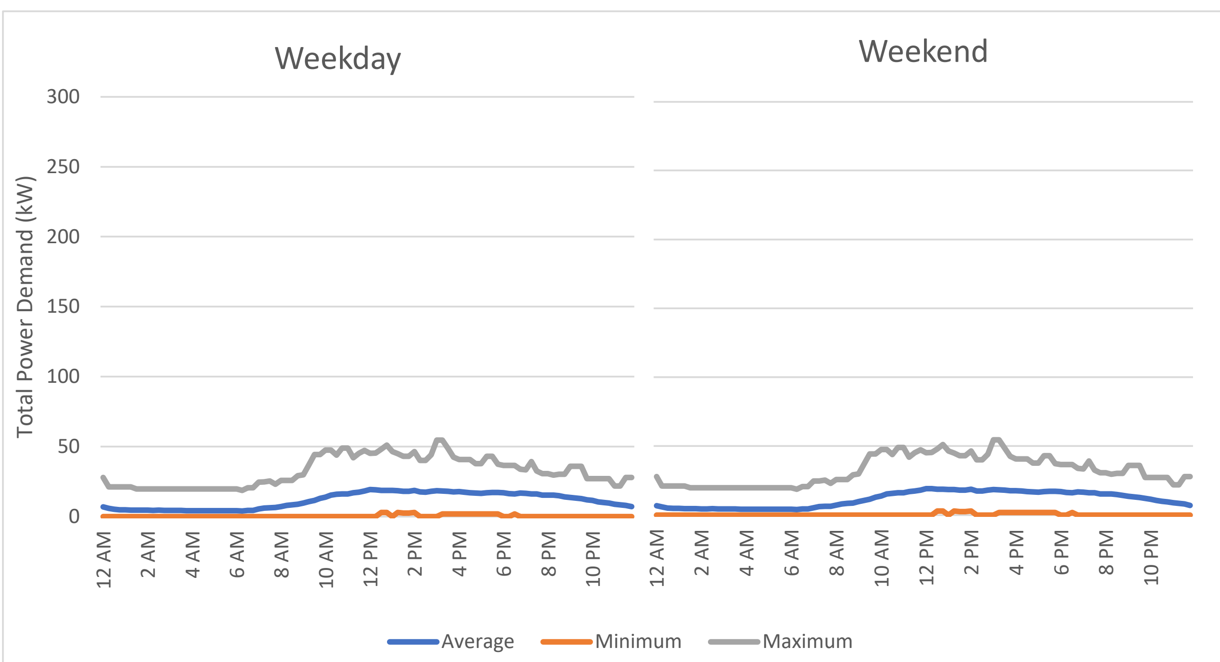


Level 2 Charging Impact on Power Grid - Medical/Educational

Port Availability: Percentage of active charging ports in use across the time of day for weekdays and weekends.

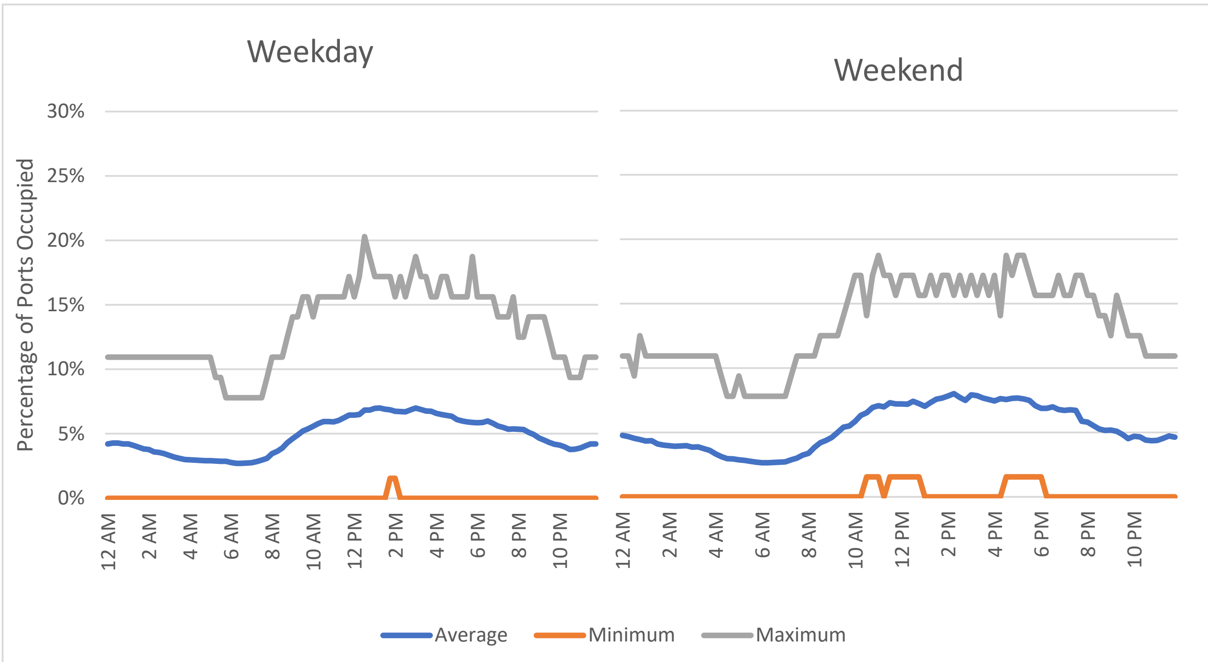


Estimated Total Charging Demand: Total power draw (calculated using average power per charging event for the charging duration) for weekdays and weekends.

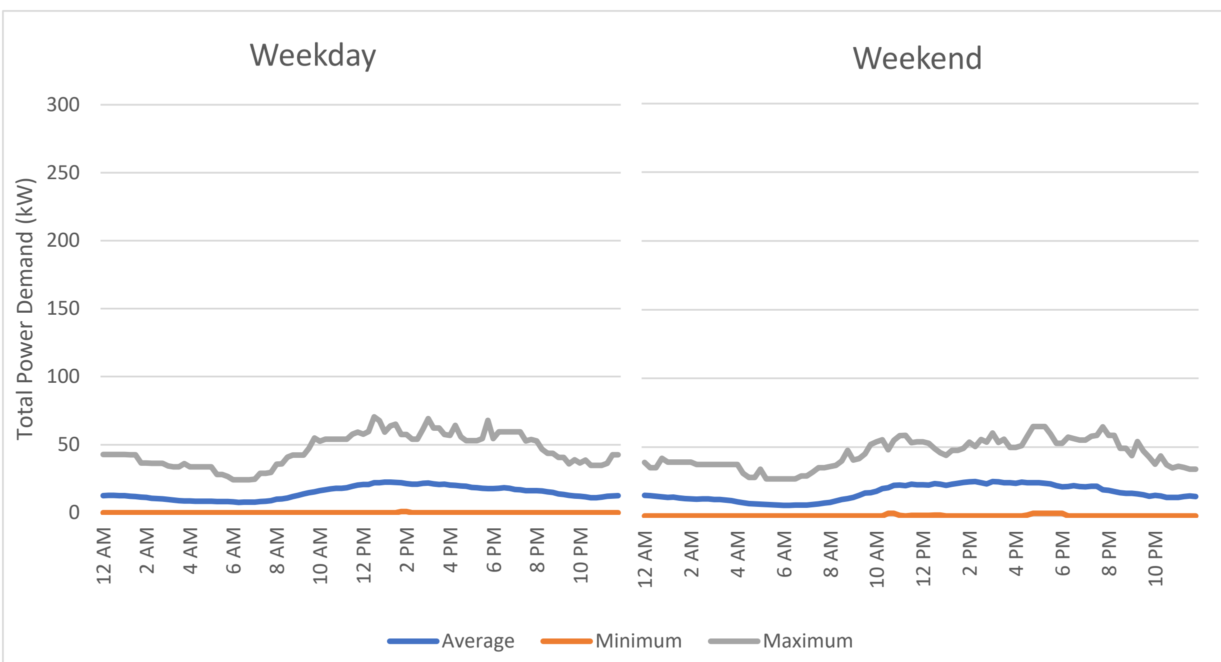


Level 2 Charging Impact on Power Grid - Leisure Destination

Port Availability: Percentage of active charging ports in use across the time of day for weekdays and weekends.

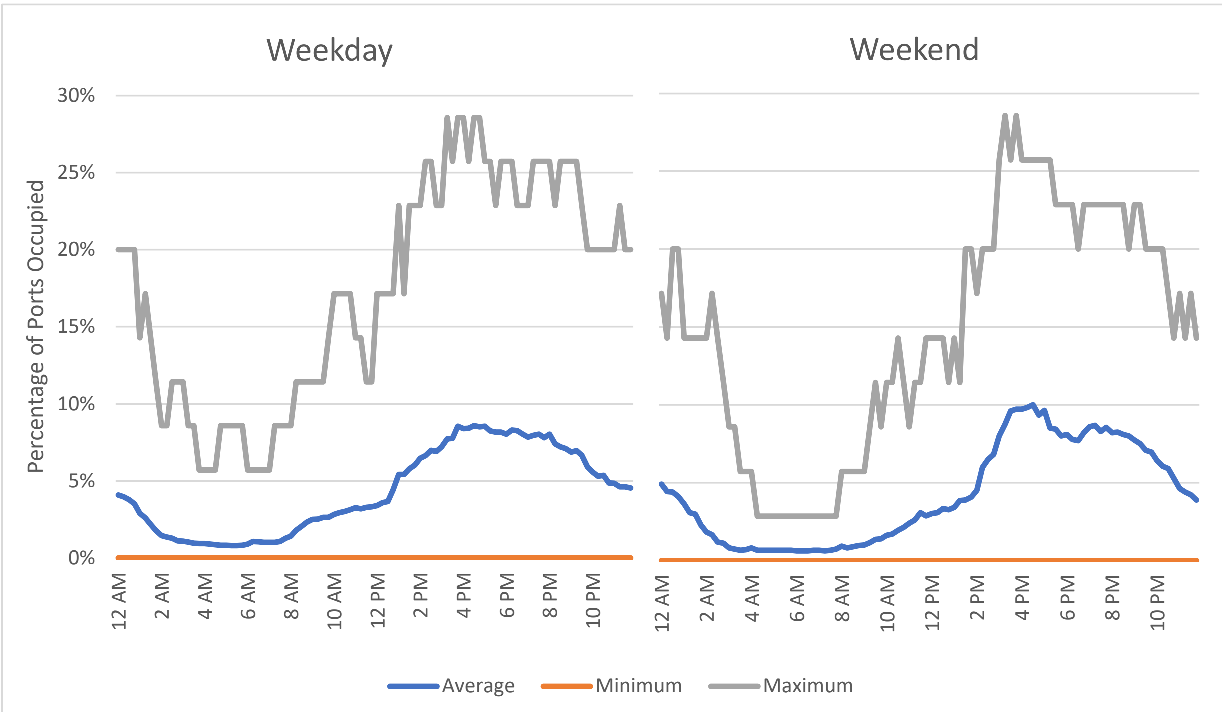


Estimated Total Charging Demand: Total power draw (calculated using average power per charging event for the charging duration) for weekdays and weekends.

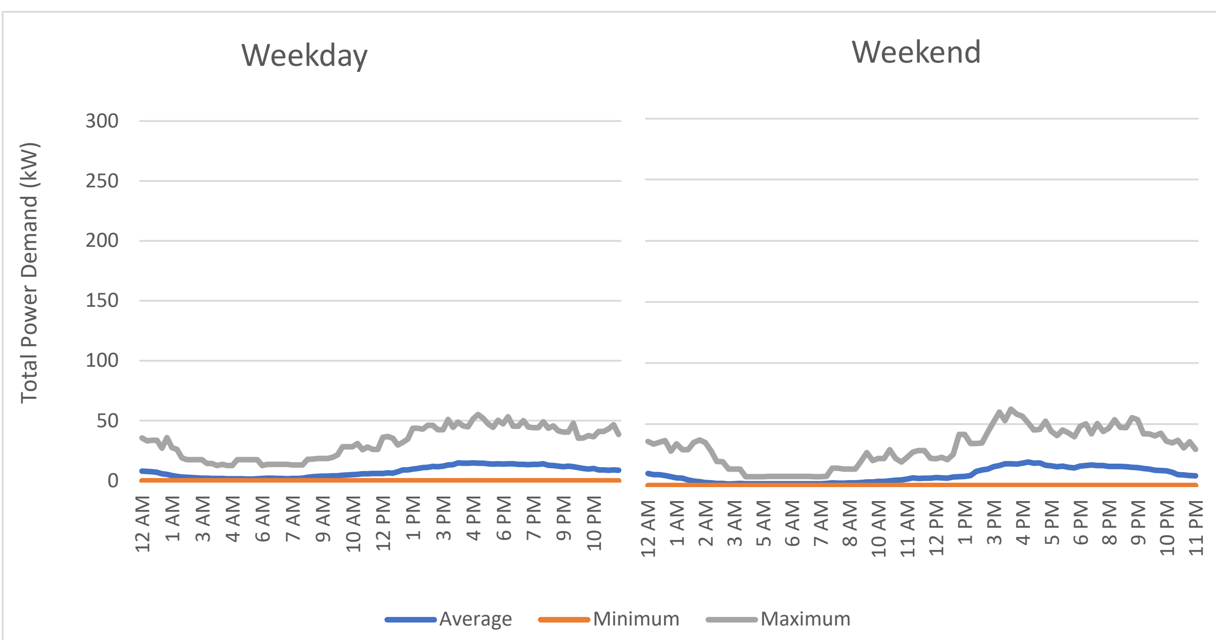


Level 2 Charging Impact on Power Grid - Retail

Port Availability: Percentage of active charging ports in use across the time of day for weekdays and weekends.

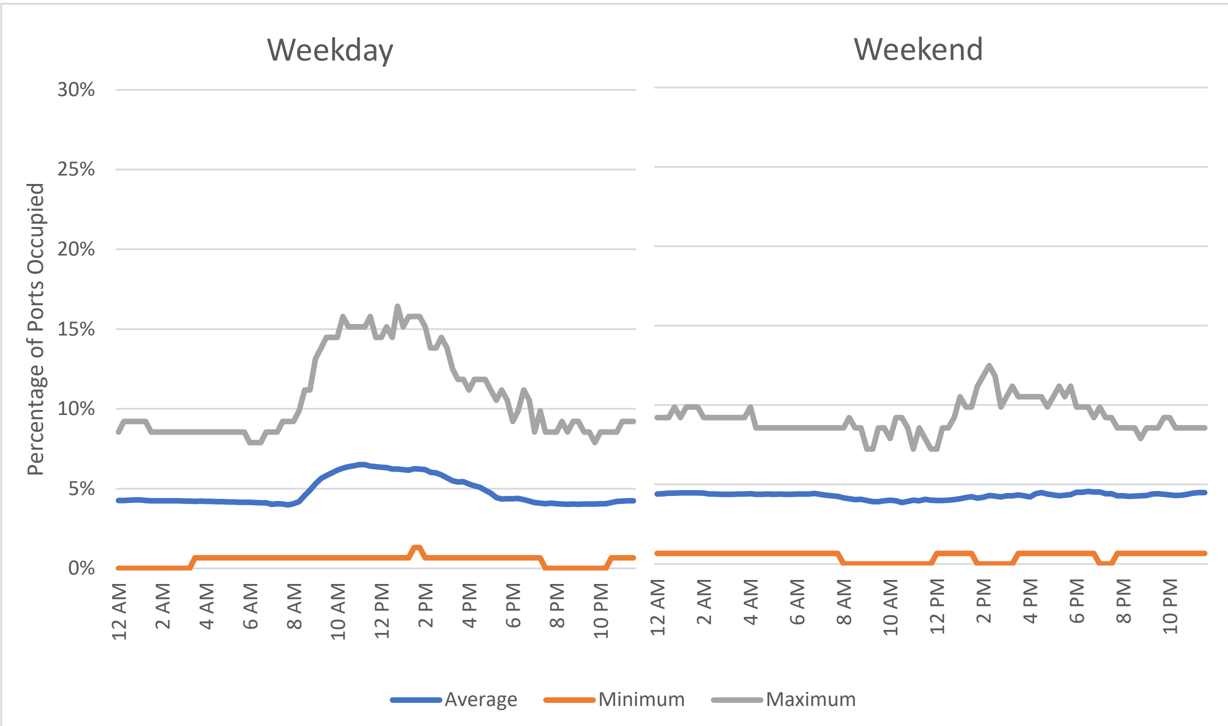


Estimated Total Charging Demand: Total power draw (calculated using average power per charging event for the charging duration) for weekdays and weekends.

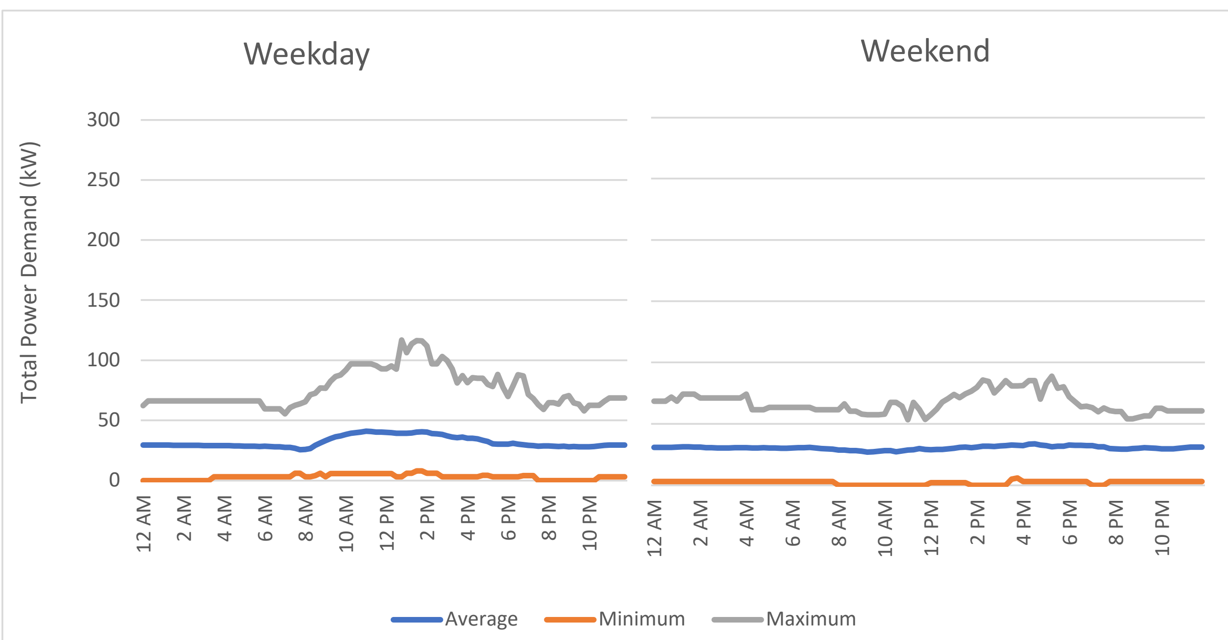


Level 2 Charging Impact on Power Grid - Multi-Unit Dwelling

Port Availability: Percentage of active charging ports in use across the time of day for weekdays and weekends.

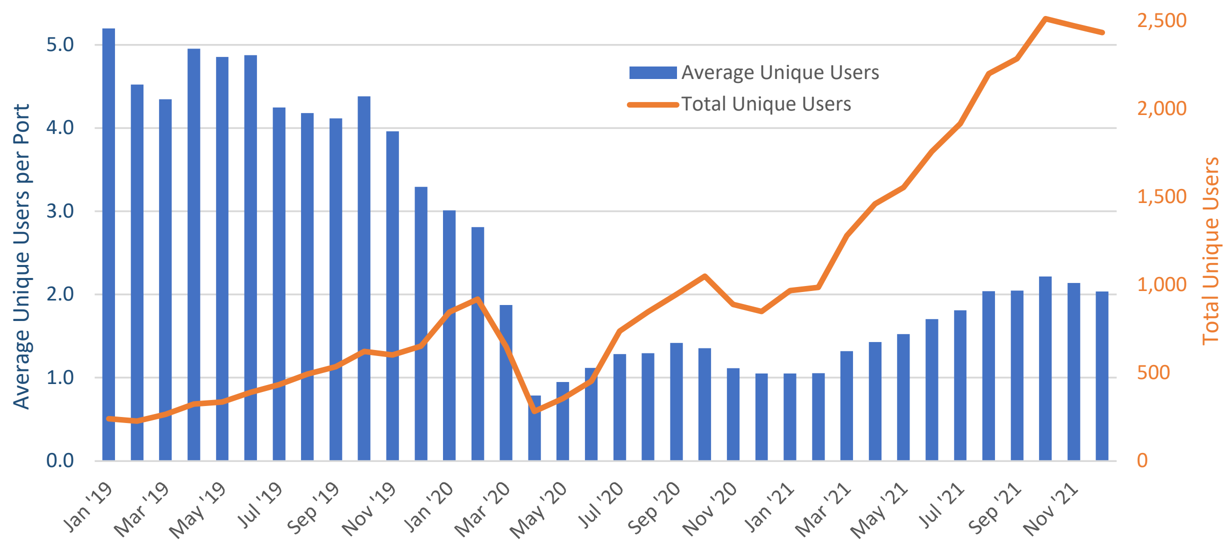


Estimated Total Charging Demand: Total power draw (calculated using average power per charging event for the charging duration) for weekdays and weekends.



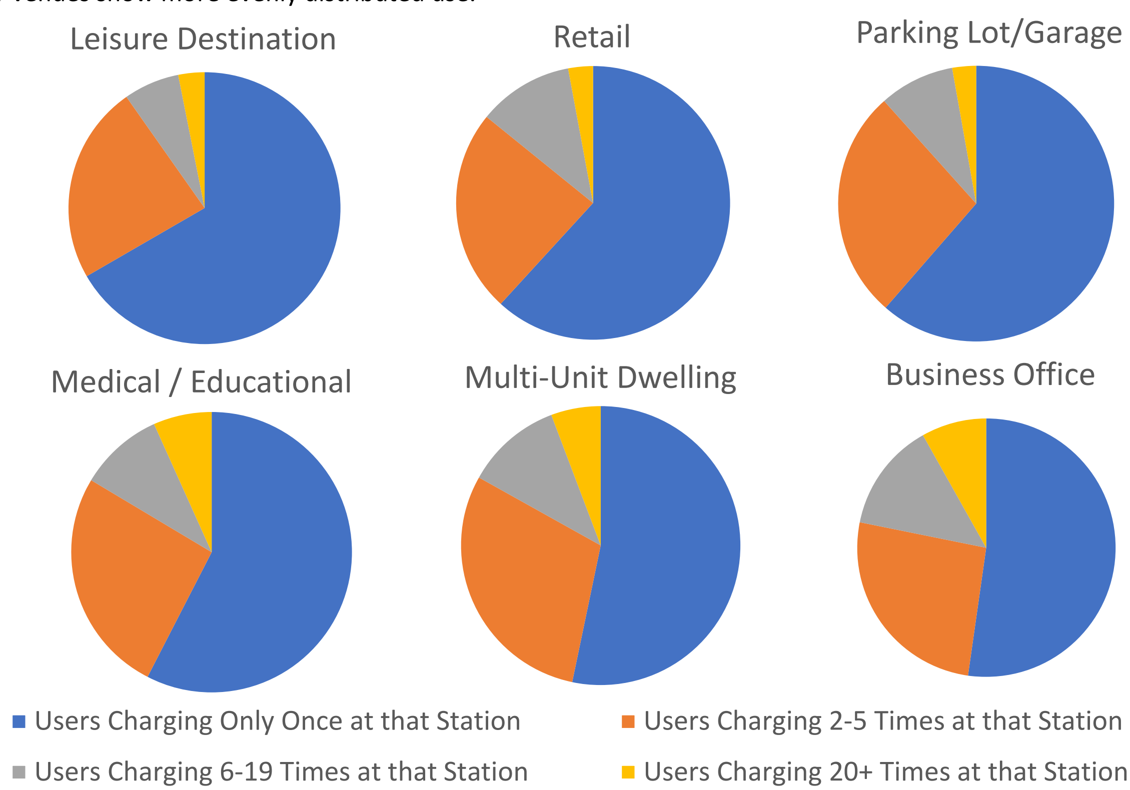
Unique EV Drivers Using the Program Charging Stations

Unique Users*: Total number of unique users per month for all stations steadily increases, but the average unique users per port remains comparatively low as new ports are installed.



* 90% of stations report user ID

Average Portion of Frequent Users: Different charging station venues will be used by a variety of different users, the majority of which might only charge there once (Leisure Destination, Retail, Parking Lot/Garage), while other venues show more evenly distributed use.



Detailed Level 2 Charging Station Usage Statistics

Venue Type	Ports	Total Days of Port Availability	Charging Events (CE)	Charging Events per day	Plug-in Time		Charging Time		% of Plug-in time spent charging	Total Energy (kWh)
					Hours	Hours per CE	Hours	Hours per CE		
Business Office	423	152,832	17,910	0.12	114,872	6.4	50,121	2.8	44%	247,396
Multi-use Parking Garage/Lot	204	68,043	25,954	0.38	106,931	4.1	66,779	2.6	62%	351,990
Multi-Unit Dwelling	237	57,226	8,585	0.15	58,308	6.8	21,698	2.5	37%	122,441
Medical or Educational Campus	116	31,737	7,979	0.25	33,843	4.2	19,567	2.5	58%	106,254
Leisure Destination	68	21,498	7,358	0.34	28,410	3.9	17,083	2.3	60%	86,296
Municipal Building	59	19,242	5,815	0.30	35,824	6.2	13,874	2.4	39%	75,219
Retail	38	13,328	9,170	0.69	13,111	1.4	10,554	1.2	81%	55,075
Transit Facility	28	10,220	573	0.06	2,450	4.3	1,233	2.2	50%	5,639
Hotel	16	5,722	599	0.10	1,931	3.2	1,038	1.7	54%	9,460
Fleet	6	2,190	1,321	0.60	17,881	13.5	3,605	2.7	20%	17,042

Region	Ports	Total Days of Port Availability	Charging Events (CE)	Charging Events per day	Plug-in Time		Charging Time		% of Plug-in time charging	Total Energy (kWh)
					Hours	Hours per CE	Hours	Hours per CE		
Boston Metro	939	297,828	69,214	0.23	342,925	5.0	174,507	2.5	51%	909,937
Western	167	54,014	9,283	0.17	26,273	2.8	16,355	1.8	62%	81,410
Southeast	89	30,195	6,767	0.22	44,363	6.6	14,690	2.2	33%	85,463

Land Use Type [1]	Ports	Total Days of Port Availability	Charging Events (CE)	Charging Events per day	Plug-in Time		Charging Time		% of Plug-in time charging	Total Energy (kWh)
					Hours	Hours per CE	Hours	Hours per CE		
Urban	1165	371,088	82,521	0.22	404,270	4.9	199,166	2.4	49%	1,044,673
Rural	30	10,950	2,743	0.25	9,291	3.4	6,386	2.3	69%	32,138
Highly Rural	0	0	0	0.00	0	0.0	0	0.0	0%	0

[1] Land Use Type Definitions
- Urban Area: population density of at least 1,000 people per square mile.
- Rural Area: Any non-urban or non-highly rural area.
- Highly Rural Area: An area having less than 7 people per square mile.

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May 17, 2021

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: D.P.U. 21-30 - NSTAR Electric Company d/b/a Eversource Energy 2020 Grid Modernization Annual Report

Dear Secretary Marini:

On April 1, 2021, NSTAR Electric Company d/b/a Eversource Energy ("Eversource" or the "Company") submitted its 2020 Grid Modernization Annual Report consistent with the directives of the Department of Public Utilities (the "Department").[1] The Company's 2020 Grid Modernization Annual Report included an update on the two battery energy storage ("BES") projects in Provincetown and Martha's Vineyard, which were originally approved by the Department in the Company's most recent base distribution rate case, D.P.U. 17-05 (2017). By this letter, Eversource provides notice of project cancellation in relation to the Martha's Vineyard BES.

Eversource has completed the third phase of the feasibility analysis for the Martha's Vineyard project, including detailed engineering and site evaluation, along with a detailed cost schedule. Based on the third-phase feasibility analysis, the Company has decided to cancel the project due to increased project costs and updated information regarding the future load forecast for Martha's Vineyard. The increased load forecast indicates the need for the construction of a 5th submarine cable to the island. Construction of a 5th submarine cable will eliminate the usefulness of the Martha's Vineyard BES. The new cable will allow for the retirement of the diesel generators without the need for the BES. This coupled with the total project forecast increase to $23.4 million, has caused the Company to make the difficult decision to discontinue with the Martha's Vineyard BES project.

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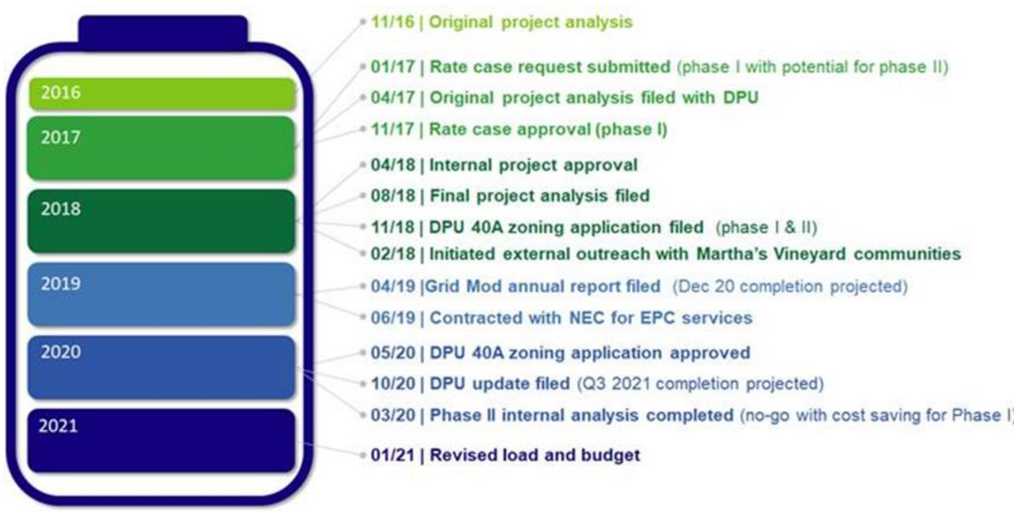
[1] Eversource, along with Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid and Fitchburg Gas and Electric Light Company d/b/a Unitil (collectively, the "Distribution Companies"), are in receipt of the March 11, 2021 memorandum issued by the Department regarding revisions to the Annual Report Templates (the "Memorandum"). The Distribution Companies requested a technical session to discuss the Department's directives regarding Section II.A. of the Annual Report template. The Department has scheduled the technical session for June 11, 2021.

Overview

In NSTAR Electric Company d/b/a/ Eversource Energy, D.P.U. 17-05 (2017), the Department authorized NSTAR Electric to undertake Phase 1 of the Martha's Vineyard BES project ("Phase 1" or "Project") consisting of a 4.9MW/20MWh Battery Energy Storage system ("BES") on Eversource-owned land at the Oak Bluffs Service Center located on Martha's Vineyard. The primary purpose of the Martha's Vineyard BES project was to significantly reduce reliance on five diesel-fired peaking generators on Martha's Vineyard that are used to supply power to the Island during high load conditions.

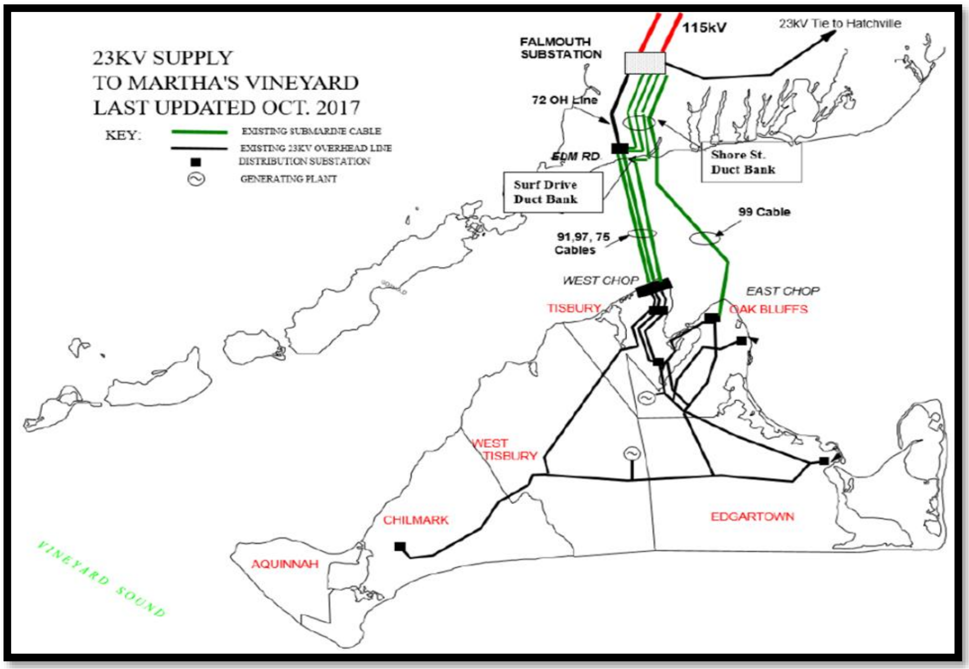
The Martha's Vineyard Phase 1 Project conceptual grade estimate was $15M. This was based on a per MWh cost projection prepared by a consulting company with experience on these types of projects. At the time the Company presented its case in D.P.U. 17-05, the $15M cost estimate represented the best approximation of the project cost available to Eversource (the Company). The Project was presented to the Department as a demonstration project.

A high-level view of the original project timeline is shown below.



Martha's Vineyard is served by four undersea cables that connect into the mainland at Falmouth. The year-round population on the Island is around 15,000 but increases to approximately 125,000 residents in the summer. Electric consumption surges on the Island in the summer and the undersea cables become strained. When this happens, Eversource relies on five diesel-fired peaking units, providing approximately 12.5 MW of supplemental power. These units were constructed in the 1950s.

The four undersea cables that connect into the mainland at Falmouth are shown below.



Eversource engineers identified Martha's Vineyard as a potential BES location given the opportunity for the BES to significantly reduce reliance on the diesel-fired peaking generators, as well as to enable the interconnection of additional solar photovoltaics ("PV") on the Island (see D.P.U. 15-122, Eversource Response to DPU-ES-2-1). This recommendation was confirmed by Eversource's expert consultant, Doosan, through its preliminary feasibility analysis. The Department approved the Company's BES project proposal in D.P.U. 17-05, with a projected cost of $15 million.

Eversource contemplated the Martha's Vineyard BES project as having two phases. The first phase would reduce reliance on two of the five peaking units. The second phase of the BES project (constructing additional battery capacity) would be evaluated for the feasibility of reducing reliance of all five peaking generators.

Design, Site Selection and Outreach Status

Following the issuance of the Department's final decision in D.P.U. 17-05 on November 30, 2017, Eversource and Doosan completed a final feasibility study for the project. This study confirmed that, in addition to the original goals for the project, the BES project would help reduce the impact during an N-1 contingency condition on the Island, potentially deferring the construction of an additional undersea cable. The Eversource team also subsequently confirmed that the BES project could be used to shave yearly and monthly peaks when not needed to reduce reliance on the peaking units, resulting in additional capacity and transmission Regional

Network Savings ("RNS") savings.

In February 2018, Eversource commenced outreach to the Town of Oak Bluffs (the "Town") about the project and specific work with the Town began in April 2018. Eversource advised of its intent to construct the BES project on Company-owned land behind its Area Work Center in Oak Bluffs. This location met the Eversource siting criteria by: (1) minimizing the visibility of the BES project for aesthetic purposes; (2) involving minimal sound impacts to surrounding properties from the BES project; (3) offering approximately one acre of space with limited or no environmental impact (i.e., no wetlands, rare species habitat); and (4) enabling an optimal electrical connection to the distribution system. The Town indicated the BES project would need to be constructed and housed in a building rather than a container solution to meet the Town's aesthetic requirements.

Eversource worked closely with the Town, meeting multiple times in person with Town select-board members, the Town Manager, the Fire Chief and Building Inspector, and the Planning Board. The Town provided feedback on height of the BES facility, roof pitch, fire safety, and other design details that Eversource was able to incorporate into an updated design of the BES project. Using this feedback, in late summer 2018, Eversource performed a permitting-level design for the BES (i.e., 30 percent engineering).

In 2020, Eversource continued to work collaboratively with the Town and held meetings with municipal officials and fire chiefs in Oak Bluffs, Tisbury and Edgartown to further discuss fire safety and respond to questions about the BES design. As part of the permitting process, Eversource regularly communicated with and responded to several requests for information ("RFI") from the Martha's Vineyard Commission ("MVC") relative to fire safety design, environmental design and anticipated operational practices. The Company anticipated continuing work to collaborate and communicate with local and regional officials and anticipated receiving all town and local approvals for the project in early 2021.

Permitting Status

Eversource filed a Chapter 40A land-use permit with the Department in late November 2018. Prior to the filing, Eversource met multiple times with the Oak Bluffs Fire Chief and Building Inspector and incorporated their input into fire safety and other design aspects. Eversource also conducted abutter outreach and participated in a public hearing in Oak Bluffs.

Eversource and the Town continued to work together during the initial siting process. In May 2019, Eversource executed a Memorandum of Understanding ("MOU") with the Town where the Town will work collaboratively with Eversource to facilitate progress of the BES project and Eversource will make certain public-health and safety and environmental commitments to assist the Town.

In 2019, the Company was referred by the Oak Bluffs Planning Board to the Martha's Vineyard Commission ("MVC") as the BES project was defined as a Development of Regional Impact (DRI). An application was filed with the MVC in 2019, and an initial presentation was conducted in July 2019. Subsequently further research was completed, and additional material was submitted to the MVC as part of that application.

In 2020, the Company continued to communicate and work with the MVC and public safety officials. This effort included multiple virtual meetings, extensive responses to requests for information from the MVC, incorporation of feedback from local public safety officials on all fire safety documents, as well as coordination with the MVC, its fire safety consultant, the Town of Oak Bluffs, the Oak Bluffs Water District and the local fire chiefs.

In April 2020, the Company received approval from the Department for its Chapter 40A petition filed in 2018. Final approval of the BES project by the MVC was anticipated in early 2021. In 2021, an emergency evacuation plan, environmental emergency response were submitted in October 2020 in support of Eversource's DRI application (DRI 691), emergency evacuation, and environmental emergency response plans. Eversource addressed concerns from the Town of Oak Bluffs relative to the previously completed groundwater analysis and agreed to incorporate additional safety measures into the facility design, including (but not limited to) conducting additional geotechnical borings to collect additional data to inform a revised groundwater analysis, commitment to install a groundwater monitoring well, and incorporation of secondary containment for the power transformers located outside of the ESS building.

Original Basis for Martha's Vineyard BES

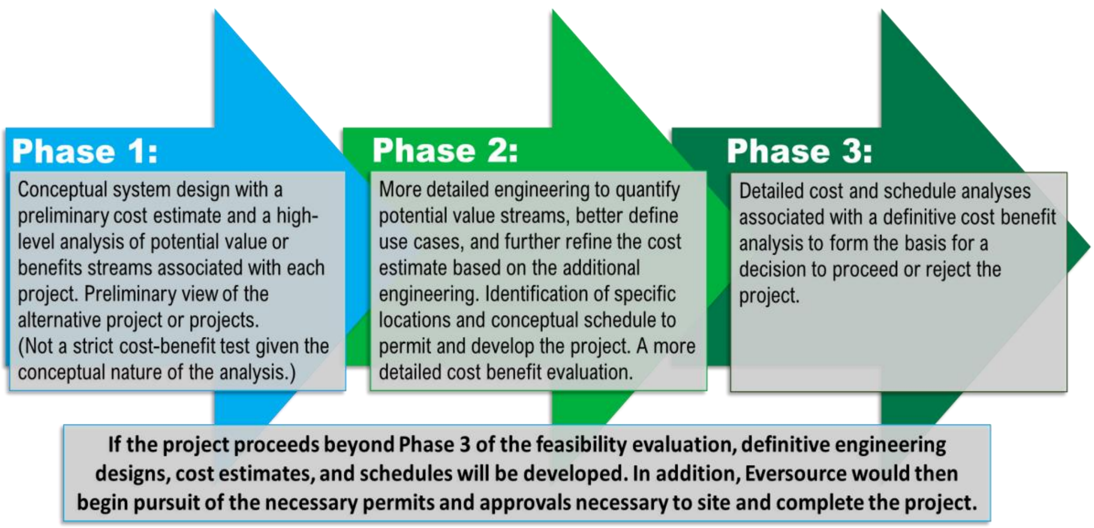
In January 2017, in the proceeding before the Department in D.P.U. 17-05, Eversource submitted testimony describing plans for its Grid Modernization Base Commitment ("GMBC"), which in part, described the Company's intent to invest in and implement BES demonstration projects in Massachusetts, generally, and on Martha's Vineyard, specifically. As stated in the GMBC, Martha's Vineyard is an island that relies on local generation during various electric-demand conditions and as a back-up to electricity supplied from the mainland by four undersea cables.

Although there are limitations on the installation, use and reliance on distributed energy resources ("DER") on Martha's Vineyard because there are inherent restrictions on land use on the Island given its geographic size, aesthetic sensitivities and other constraints (such as difficulties in managing voltage stability due to the high ratio of generation to load), the Company's experience and knowledge of the island indicated that opportunities for increased reliance on wind or solar generation exist. However, the Company has found that, with the current level of DER integration, it is more costly than anticipated to interconnect incremental DER because significant additional distribution upgrades become necessary.

Adding energy storage, with other improvements, would allow the Company to frequently utilize the ESS in place of the aging diesel generators on the Island. As a result, Eversource planned the Martha's Vineyard BES as a way of meeting system requirements while reducing greenhouse gas ("GHG") emissions associated with the generator operation. This approach was intended to allow for the deferral of other distribution investments, while enhancing system reliability on Martha's Vineyard, and creating opportunities to integrate additional DER.

Feasibility Analysis

In D.P.U. 17-05, the Company committed to a detailed, phased, technical and financial analysis of each project based on the costs and benefits of each project (Exhs. AG 32-2; DPU 57-7; Tr. 1, at 175-180; Tr. 10, at 3180-3183). Eversource confirmed to the Department that the two BES demonstration projects would not move forward until acceptable levels of detail on costs and benefits for internal review and approvals are obtained (id.). This is consistent with the Company's process for any capital project it undertakes (id.).



The Company's phased approach for evaluating the identified energy storage projects is a three-part process. The Company stated that during Phase I, the Company would analyze the project need or the specific issue or problem on its electric system that it seeks to resolve through implementation of energy storage. Based on this analysis, the Company would develop a conceptual design at a high level including the technical parameters of the energy storage system and how the system would potentially perform to meet the identified need. The Company would then explore the technical feasibility associated to engineer and construct the storage solution. The Company asserted that this process would allow the Company to make its first decision regarding the proposed project. If the results of this first phase were favorable, the Company would move on to Phase II.

Phase II would involve additional conceptual design work, including development of a preliminary cost estimate, development of a preliminary base case, and a development of a preliminary timeline for implementation. The results of this analysis will result in the second opportunity for the Company to decide whether it should move forward with additional evaluation and analysis.

Following a favorable result of Phase II, the Company would move on to Phase III. During this final analysis phase, the Company would begin baselining the proposed project and conducting the detailed design, schedule estimates, and business case including issuance of a Request for Proposal (RFP) to qualified vendors that would construct the solution. This final phase would provide the Company with enough information to consider internal technical and financial approval of the project.

Eversource requires internal corporate approval (up to the executive board) if required based on project size and cost. This process protects the Company before a decision is made to proceed with significant spending in any cost category including detailed design work and beginning the permitting and siting process. This phased approach combined with the Company's rigorous internal approval process makes it clear that the Company will only move forward with energy storage projects after a reasoned decision process.

Challenges Identified through Phase III Feasibility Analysis

- Project Delays and Increased Cost

To keep the project moving ahead and be able to complete it within the five-year time frame provided in the Department approval, the Company began activities in parallel with the permitting process. The NEC Energy Solutions contract was awarded for BES EPC and limited notice to proceed was issued to purchase switchgear and conduct engineering.

However, in June 2020, Eversource received notification from NEC Energy Solutions that they were exiting the energy storage business. Eversource, together with NEC, worked diligently to develop and execute a viable plan to ensure the two Energy Storage Projects are successfully built and energized. The parties continued to meet on a regular basis to keep the lines of communication open and ensure proper execution of the plan. Engineering work is substantially complete, including design updates to lower costs from original estimates.

In addition, several other contingencies occurred. Specifically, civil construction bids were received at three times higher than expected amount. Extensive negotiations with fire chiefs were conducted, but not completed in relation to the permitting process with Martha's Vineyard Commission and Land Use Planning Committee. The Company anticipated the imposition of a requirement to revisit the Department's 40A permit approval based on design changes as a result of requirements imposed by these two committees.

Due to these factors, the estimated project cost increased substantially. The current budget estimates are included below.

Battery Energy Storage Project				
Martha's Vineyard				
	Current Forecast	**Approved Budget**	**Variance**	**Variance Explanation**
Eversource Labor	$1.1	$0.5	$0.5	Additional Project Management and Internal Engineering
Eversource Material	$0.3	$0.2	$0.1	
Outsource Engineering	$2.3	$0.2	$2.1	Additional contractor integration and performance studies.
Outsource Siting & Permitting	$1.0	$0.6	$0.4	Increased complexity of siting and permitting.
Civil Construction	$4.2	$0.5	$3.7	Budget assumed containerized solution.
Building Construction	$2.6	$1.4	$1.2	Budget assumed containerized solution.
NEC (ESS EPC)	$8.1	$7.7	$0.4	Addition of ventilation system.
Indirect, Overhead & AFUDC	$1.6	$1.7	$(0.1)	Extended project duration. Change in overhead rates.
Contingency	$2.3	$2.1	$0.2	
Total Project	**$23.5**	**$15.0**	**$8.5**	

The primary reason for the increased costs above the initial, conceptual estimate of $15 million is as follows:

a. At the time the Company proposed the MV Storage Project, the Company's conceptual design used a containerized solution that would not require the siting or construction of a building to house the storage system.

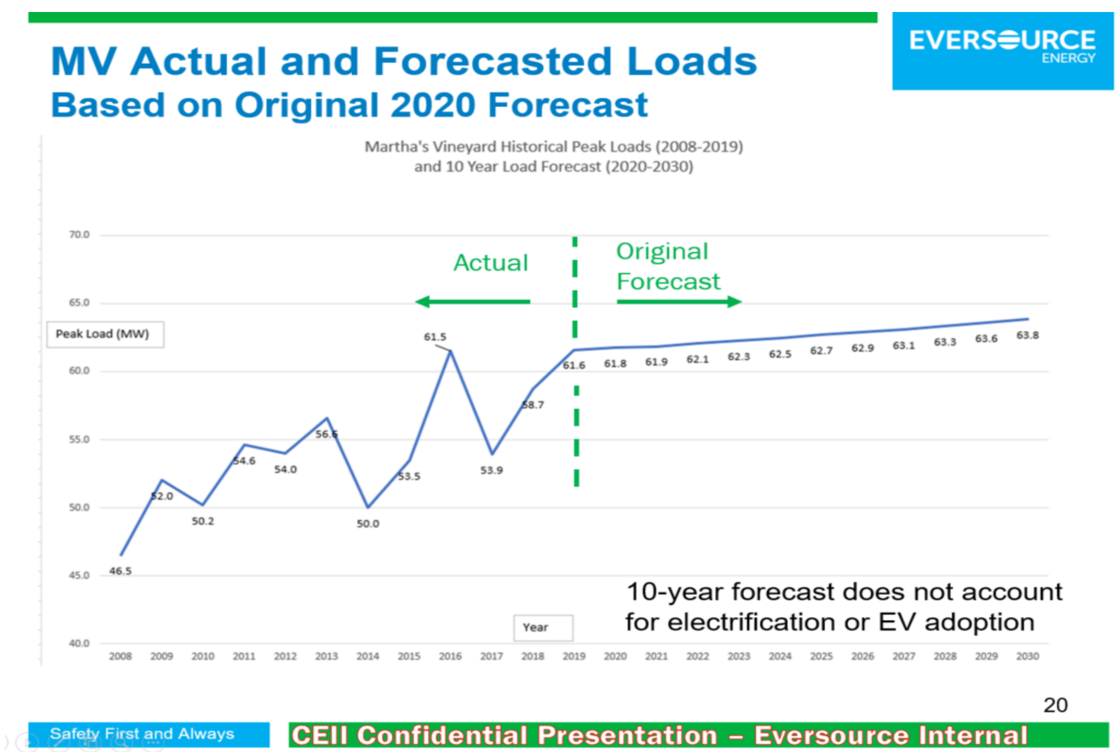
b. The Town of Oaks Bluff is requiring the Company to construct a building to house the storage system, rather than the containerized solution due to perceived visual impacts.

c. The cost of the building, foundations, required civil work and wall construction, plus the cost of obtaining the permits for the revised plan, account for approximately $5M of the $8.5M additional costs above approved budget.

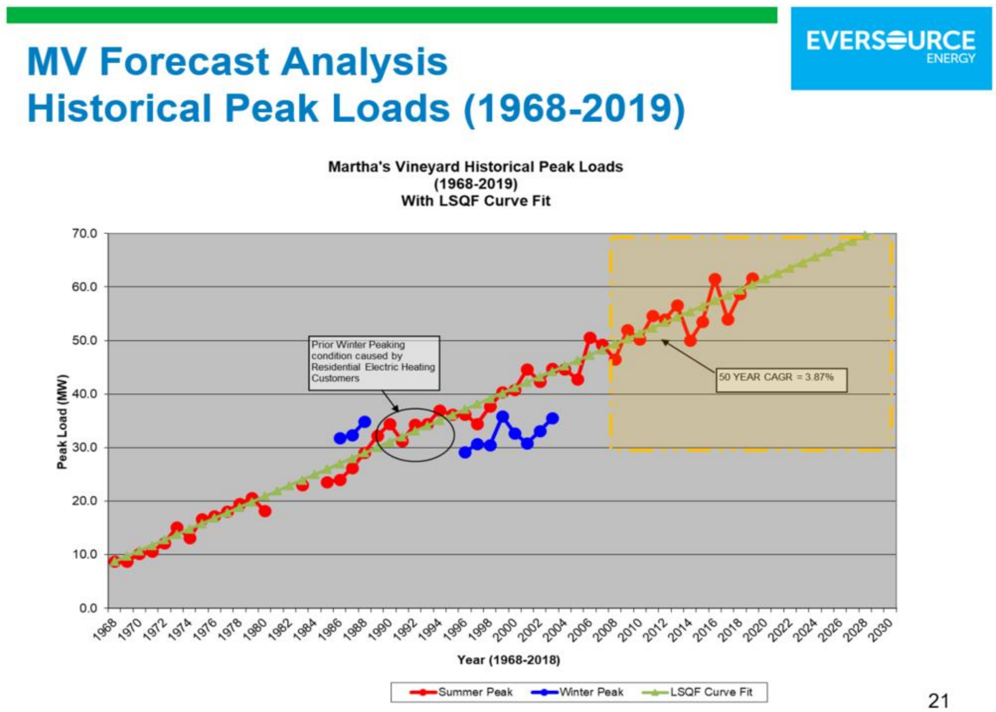
d. Cost for ventilation system for additional fire safety protection that was determined to be best practice following the root cause report on the McMicken fire in AZ that was issued in July of 2020, account for approximately $1M of the $8.5M additional costs above approved budget.

- Updated Load Forecast

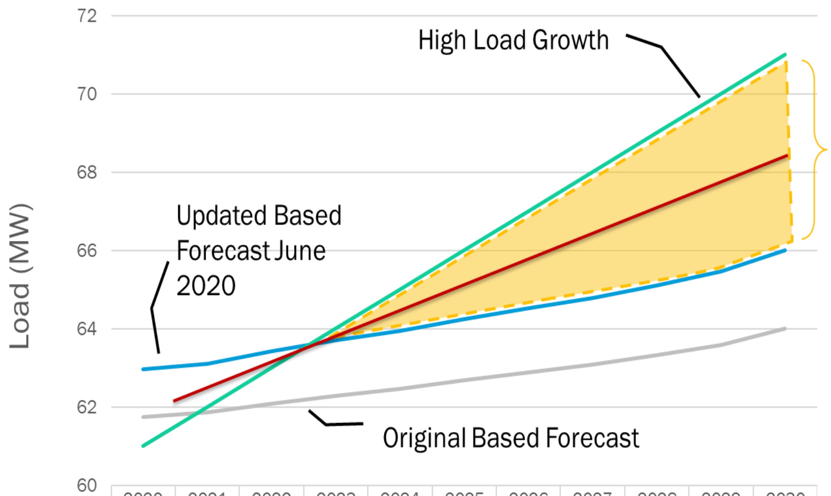
At the time that the Martha's Vineyard BES was originally scoped out, the base 10-year, 90/10 load non-coincident forecast for Martha's Vineyard was 62 MW for 2020, increasing to 64 MW by 2029. This reflected a relatively low growth rate because Martha's Vineyard was treated as a sub-area out of Falmouth Substation #933 with a portion of the Upper Cape area due to the top-down approach used to develop the substation forecast from the forecasted system peak, with heavy penetration of energy efficiency and demand response measures. A comparison of this Martha's Vineyard load forecast versus recent historical peaks is shown below.



As a sensitivity analysis, System Planning also analyzed Martha's Vineyard historic peaks far as far back as possible using documented records– annually back to summer 1968. A least-squares curve fit (LSQF) was conducted for all historical peak data points from 1968 to 2019 and which revealed a 50-year Cumulative Annual Growth Rate (CAGR) of approximately 3.7% per annum.



Given the contrast between the Based Original forecast and the Historical Peak Load, the Martha's Vineyard load forecast development was revisited by System Planning and Eversource Load Forecasting in June 2020 to produce a sub-area load forecast for Martha's Vineyard, which is more reflective of actual historical load growth rates on the Island. As shown below, the net effect of the changes to the original (pre-June 2020) load forecast is a higher load forecast increased from 63MW in 2020 to 65MW in 2029, or approximately 1MW higher than the original forecast for 2029. The revisions to the load forecasting methodology and the sensitivity analysis completed with historical information reveal a shifted load growth with a higher growth rate than the original pre-June 2020 forecast. Refer to figure below showing the Original Based Forecast, Updated Based June 2020 Forecast, and a sensitivity analysis accounting for the historical LSQF curve.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Original 2020	62	62	62	62	62	63	63	63	63	64	64
Updated June 2020	63	63	63	64	64	64	65	65	65	65	66
Medium	61	62	63	63	64	64	65	66	66	67	67
High	61	62	63	64	65	66	67	68	69	70	71

In February 2020, Eversource representatives met with the Martha's Vineyard Commission, which has established a Climate Action Task Force (MVC/CAT) to evaluate and develop plans, a roadmap, and policies to reduce and potentially eliminate fossil fuel use on the island and the increase the fraction of electricity use that is considered renewable. The CAT's high-level goals include:

- Foster increased Energy Efficiency (EE) and conservation.
- Electrify all transportation and building-related energy use.
- Promote and ensure a carbon-free electric supply.
- Promote a resilient electric supply.

Specific CAT goals and expected benchmarks include:

- Reduction in fossil fuel use on the Island.
  - A 50% reduction by 2030
  - A 100% reduction by 2040
- An increase in the fraction of electricity use that is considered renewable.
  - A 50% of electric energy use by 2030

- A 100% of electric energy use by 2040

The Martha's Vineyard Commission CAT has produced specific whitepapers for development plans and policies to attain these stated goals including:

- An Electric Sector Whitepaper (rev 6/1/2020) promoting a higher penetration of electric heat pumps and reduction of reliance on fossil fuel use.
- A Transportation Energy Plan (rev 5/1/2020) promoting a higher penetration of EV usage.
- An Island Energy Plan whitepaper promoting higher penetration and targeting of Energy Efficiency Measures.
- An Island Energy Plan whitepaper promoting more stringent standards for HVAC.

Eversource's review of these goals and methods shows that these goals will *increase* the existing (base) 10-year load forecast for Martha's Vineyard, with most of the change arising from a higher penetration of EV (Electric Vehicle) adoption. However, it is expected that the adoption rate will be like that for the greater Northeastern United States. Similarly, the CAT's plans for HVAC buildings and targeted Energy Efficiency (EE) (typically, promotion of use of heat pumps and a proposed ban on use of fossil fuel for heating or hot water) will mostly affect the winter peak loading and will not have a significant effect on the summer peak forecast. Eversource further observed that many of the CAT's initiatives are not policy-driven but were expected to be a function of improved consumer education and the availability of incentives.

Eversource is continuing to work and meet with the MVC Climate Action Task Force on these initiatives; however, it appears that the higher (LSQF) Martha's Vineyard load forecast (70 MW by year 2029) as an upper band to load growth covers the expected load increase that may arise from these goals. In addition, Eversource is working to develop a probabilistic load forecasting tool which will consider EV growth and future electrification goals.

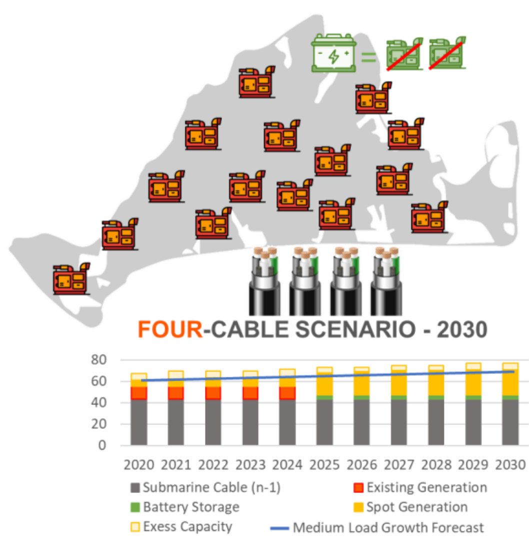
- <u>Change in Circumstances on Existing Diesel Generators</u>

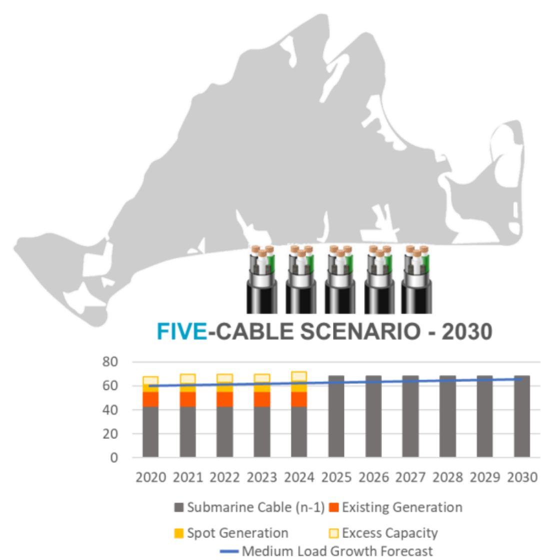
In addition to the revised load forecast, the Company was required by contract with the existing (five) diesel generators on the Island to determine if the contract should be amended to continue beyond the current term of 2025. As part of that review that contract, which was recently sold to a new owner, the Company found that there was an expectation that the operations cost to be significantly higher to renegotiate; that the diesel age will require significant investment in the future; and, that it was unclear what the motivation of the new generator owners is going forward. It was also determined that spot generators are a viable, cost effective alternative for emergency situations on the Island if necessary. Therefore, the Company has determined it was in the best interest of customers to not extend the contract beyond 2025.

Based on the revised load forecast and assuming removal of support from the existing five diesel units per the expiration of the contract in 2025, total firm capacity available to the island for an N-1 cable outage is 48 MVA. Continued reliance on the output of the diesel units, plus the output of the 4.9 MW BES available in 2021 for the 2021-2025 timeframe yields a 60.5 MVA firm capacity limit, which will require continued reliance on portable diesel units as all load forecasts exceed this value and would not be a viable long-term option.

- <u>5th Cable Scenario</u>

The Company determined that, with a medium range peak load forecast of 67MW in 2030, the fifth-cable scenario will be sufficient to supply to the Island under N-1, *excluding the diesels after 2025 and the 4.9MW BES*, as shown below.





The 5th cable project would involve the Falmouth substation to be reconfigured so to provide additional mitigation of risk to supply to MV by constructing a new 23kV feeder position at Falmouth Substation. Risk of supply to Martha's Vineyard would be further mitigated by installing the 5th cable in a new duct and manhole system between Falmouth Substation and the shore at Elm Road, so that all the cables supplying Martha's Vineyard would not be in the same duct route, minimizing mutual heating effects and reducing the risk of mutual impacts (<u>e.g.</u>, a cable fault affecting other circuits in the duct bank).

The additional cable would also make system serving Martha's Vineyard more robust in general, which should improve the voltage profile for all customers including related to the potential to increase the amount of solar that can be integrated on the Island. The addition of the 5th cable would permit the existing 23kV distribution system on Martha's Vineyard, which is currently supplied by the four existing cables, to be reconfigured so that the loading and total customer counts on all five cables are optimized to improve both capacity and customer reliability. The addition of the 5th submarine cable would also permit an incremental increase in DER hosting capacity on Martha's Vineyard. Nevertheless, this will be limited to the areas of the Island directly fed off the new cable or on 23kV circuits that are relieved by it.

Conclusion on Project Cancellation

At this point, the Company has completed the third phase of the feasibility analysis for the project, including detailed engineering and site evaluation, along with a detailed cost schedule. The updated engineering analysis and detailed cost estimate is forming the basis for a decision to not move ahead with the project.

The Company has decided to cancel the project based on increased project cost and updated information regarding the future load forecast for Martha's Vineyard. The increased load forecast has driven the need for the construction of a 5th submarine cable to the island. The 5th submarine cable installed will meet these future load expectations, eliminating the usefulness of the Martha's Vineyard BES. The new cable will allow for the retirement of the diesel generators without the need for the BES. This coupled with the total project forecast increase to $23.4 million, has caused the Company to make the difficult decision to discontinue with the Martha's Vineyard BES project.

Thank you for your attention to this matter. Please contact me with any questions you may have.

Sincerely,

Danielle C. Winter, Esq.

Enclosures

cc: Tina Chin, Hearing Officer
Daniel Licata, Hearing Officer
Greggory Wade, Hearing Officer
D.P.U. 15-120, 15-121, and 15-122 Service Lists