Fitchburg Gas and Electric Light Company (d/b/a Unitil)

2022- 2025
Grid Modernization Plan
Term Report

Massachusetts Department of Public Utilities
D.P.U. 26-93

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Acronyms and Abbreviations

ADMS – Advanced Distribution Management System

AMI – Advanced Metering Infrastructure

API – Application Programming Interface

CIS – Customer Information System

CVR – Conservation Voltage Reduction

DA – Distribution Automation

DER – Distributed Energy Resource

DERMS – Distributed Energy Resource Management System

D.P.U. – Department of Public Utilities

FAN – Field Area Network

FLISR – Fault Location, Isolation, and Service Restoration

GIS – Geographic Information System

GPS – Global Positioning System

GMP – Grid Modernization Plan

IVR – Integrated Voice Recognition

LTC – Load Tap Changer

OMS – Outage Management System

PLC – Power Line Carrier

PLX – Gridstream PLX Technology

RFP – Request for Proposal

SCADA – Supervisory Control and Data Acquisition

UBLF – Unbalanced Load Flow

UES – Unitil Energy Systems, Inc. (Unitil's affiliate distribution company in NH)

VAr – Volt Ampere Reactive

VVO – Volt VAr Optimization

WFM – Workforce Management

1 INTRODUCTION

In D.P.U. 21-82, the Massachusetts Department of Public Utilities ("Department") ordered Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid"), Fitchburg Gas and Electric Light Company d/b/a Unitil, and NSTAR Electric Company d/b/a Eversource Energy ("Eversource") (together the "Companies") to file a Term 2 Grid Modernization Plan ("TERM 2 GMP") covering the timeframe of 2022 to 2025. In compliance with the Department Orders in D.P.U. 21-82 on July 1, 2021, Fitchburg Gas and Electric Company, d/b/a/ Unitil (the "Company") submitted a comprehensive TERM 2 GMP that described a scope and schedule for 1) a continuation of investments that were previously authorized in the Company's original Grid Modernization Plan ("TERM 1 GMP") and 2) projects that were not previously authorized in the TERM 1 GMP.

On October 7, 2022, the Department issued D.P.U. 21-80-A; D.P.U. 21-81-A; D.P.U. 21-82-A ("Order A") approving in part the continuing investments for the TERM 2 GMP for the EDCs. See Order A at 114-115.

On November 30, 2022, the Department issued D.P.U. 21-80-B; D.P.U. 21-81-B; D.P.U. 21-82-B ("Order B") approved the new grid-facing and customer-facing investments for 2022 to 2025 subject to the directives contained in the order. See Order B at 337. The Department preauthorized the Company's core AMI investment which involves the accelerated transition and replacement of its existing older-generation TS2 meters with PLX AMI meters. See Order B at 273-274. The Department categorized the Company's Customer Engagement and Experience and Data Sharing Platform projects as supporting AMI investments. Instead the Department provided preliminary approval of these two investments and expects additional details for these investments to be submitted in future AMIF cost recovery filings to determine if accelerated cost recovery for these investments is appropriate. See Order B at 275-276. As explained in this Report, the Company filed a petition with the Department (D.P.U. 24-54) to revise the scope of the original AMI project and obtain preauthorization of certain AMI investments in connection with the revised scope. On March 28, 2025 the Department issued an order (D.P.U. 24-54-A) approving this petition. The capital investments and O&M costs presented in this report represent the revised AMI project scope

On January 25, 2023, the Department issued a memorandum which assigned the docket number D.P.U. 23-30 for the Company's calendar year 2022 annual report filing as well as defining the form and content of the annual report and annual report template. This memorandum included Attachment A which described the outline for the annual report and Attachment B which is the data reporting template.

On April 3, 2024, the Department issued a memorandum which assigned docket number D.P.U. 24-40 for the Company's calendar year 2023 annual report filing as well as defining the form and content of the annual report and annual report template. The memorandum included Attachment A which described the outline for the annual report and Attachment B which is the data reporting template.

On April 8, 2025, the Department issued a memorandum which assigned docket number D.P.U. 25-32 for the Company'ss calendar year 2024 annual report filing. The memorandum instructed the Companies to use the same narrative outline and data reporting template used for the CY 2023 grid modernization annual reports.

On May 29, 2026, the Department issued a memorandum which assigned docket number D.P.U. 26-93 for the Company'ss Second Grid Modernization Term report filing as well as defining the form and content of the term report. The memorandum included references to templates describing the outline for the term report and attachment which is the data reporting template.

This 2022-2025 Grid Modernization Term Report and associated templates are filed pursuant to the Department's orders in D.P.U 21-82 as well as the memorandums in D.P.U. 23-30, D.P.U. 24-40, and D.P.U. 26-93. This report is designed to demonstrate the Company's final status of implementing the investments as identified in its Term 2 GMP filing.

1.1 PROGRESS TOWARDS GRID MODERNIZATION OBJECTIVES

The Company's approach to filing its original GMP was to provide a 10-year plan of projects as opposed to a group of projects to be executed over a three to four-year term. The Department approved the Grid Facing projects proposed and the Company has worked towards implementing these projects since the original GMP was approved in 2018 and Term 2 was approved in 2022.

This Grid Modernization Term Report covers activities in 2022-2025 and describes the Company's progress and final status of implementing its Grid Modernization Plan. The report begins with the Company's approach to implementing its GMP, describes the cost and performance tracking measures adopted and the project approval process. Section 2 describes the Company's approach to implementation of the program. Section 3 describes in more detail the implementation of grid modernization investments by investment category. Section 4 of the report describes and reports on statewide and company specific infrastructure investments. Section 5 describes the evaluation consultant recommendations. Section 6 describes the company-specific project reporting. Section 7 provides a conclusion to the report.

Overall, the Company substantially completed the Grid Modernization plan as originally filed. The templates developed as a means to measure progress associated with the plan focus primarily on number of units installed and the amount of money spent on the implementation.

In 2025, the Company was successful in continuing the implementation of its ADMS system per the 2022-2025 Grid Modernization Plan. GMP-related SCADA implementations were completed at Princeton Road and Pleasant Street substations. This completed the plan to implement SCADA at substations per the 2022-2025 Grid Modernization Plan. The evaluation testing of the VVO on the circuits emanating from the Summer Street, Lunenburg Substation, and West Townsend substation. This completed the VVO project within the 2022-2025 Grid Modernization Plan. The implementation of VVO will continue as part of the Electric Sector Modernization Plan (ESMP). As part of the ADMS project, in 2025 the Company began its initial DERMS implementation efforts. This effort will continue as part of its ESMP. The Company completed the installation of the AMI software Head-End System (HES) and the installation of the field area network (FAN) and the replacement of all electric meters. The DER Mitigation effort was completed in 2025 by completing the implementation at the Summer Street substation.

The Company completed the installation of the FAN backbone in 2022, essentially completing the planned FAN project. Since 2023, the incremental addition of endpoint devices associated with VVO were charged to the VVO project.

The Company experienced some challenges associated with the implementation of the Mobile Information Management System (MIMS)[1] in the Workforce Management Category. The Company was not able to fully deploy the system by the end of year 2025. For this reason it is not included in the Grid Modernization cost recovery request. However, the implementation of the project continued and was completed in 2026.

The Company shifted its approach to digital customer engagement as customer needs and industry trends evolved. The Company contracted with Systems & Software (existing CIS vendor) and launched the system in April of 2024. In early 2025, several system enhancements were executed, including enhanced outage alert functionality designed to proactively alert customers of an outage affecting their service location and to provide real-time outage status updates. The Company plans to continue the efforts of customer engagement in future years outside the Grid Modernation Plan.

1.2 SUMMARY OF GRID MODERNIZATION DEVELOPMENT (ACTUAL V. PLANNED)

The Company continues to make significant progress towards the implementation of its GMP. Since the Order was issued, the Company has been working on the more detailed design and analysis required to implement the investments identified in its GMP. In 2019, after detailed discussion with the project teams and vendors, the Company decided to modify the plan schedule to coordinate the design and installation of SCADA, ADMS, VVO and FAN projects. In 2020, the Company accelerated the implementation of an ADMS ahead of the original GMP schedule. In 2022, the Company was also successful with the initial implementation of VVO field equipment, substation SCADA and FAN communication for VVO and SCADA projects. Since that time, the implementation of the SCADA, VVO, and ADMS systems, as well as the FAN communications between these systems has been progressing per the plan. VVO has been implemented at four substations and is communicating with the ADMS. The SCADA deployment also continued at new locations during the year. The implementation of the mobile damage assessment was delayed due to an upgrade of the GIS software version the company was using. The Company filed a petition with the Department to modify the scope of the AMI project (D.P.U. 24-54) which was subsequently approved by the Department (D.P.U. 24-54-A). During 2024, the Company made significant progress toward the deployment of the new AMI system including the head-end system (HES) and the installation of the fiend area network. Also, as result of the change in the scope of the AMI project, from a meter replacement project to a complete AMI system replacement, the AMI and OMS integration project will be completed as part of the HES system integration as opposed to a separate project. In 2025, the company completed the replacement of the AMI

[1] MIMS is the software chosen for the mobile damage assessment platform

system, continued the implementation of VVO, SCADA and ADMS, completed the DER mitigation efforts, and enhanced our digital customer engagement.

The Company's coordinated deployment of these grid-facing investments will expedite the achievement of grid modernization objectives and allow the Department to more accurately assess the benefits to customers relative to the costs. The progress towards implementing each of the grid modernization investments is summarized below.

<u>Monitoring and Control Investment Category</u>
The Monitoring and Control investment category included two projects from the Company's GMP. The first project was a Supervisory Control and Data Acquisition (SCADA) project to expand the coverage and functionality of Company's SCADA system. The second project was to further integrate OMS with the Company's AMI system. The integration of AMI with OMS project was cancelled per order D.P.U. 24-54-A as described below in the summary of AMI.

The Company completed the SCADA implementations at nine substations in its GMP (Rindge Road, Townsend, Beech Street, Lunenburg, Nockege, River Street, Canton Street, Princeton Road, and Pleasant Street).

<u>Volt/VAr Optimization Investment Category</u>
From the initiation of the GMP, the Company has completed the installation and commissioning of equipment for all circuits emanating from four substations. This equipment is communicating with the ADMS system and is currently operating under local automatic control. The evaluation (On/Off) testing, which expands 9 – 12 months, has been successfully completed for four substations The material for the fifth substation has been ordered. Some equipment has been received, with the final material expected to be delivered in early 2026. The Company plans to continue to incorporate the installation of controls on all circuits emanating from one substation per year, as detailed in a later section of this report. Because of material lead time the ordering of material is planned two years prior to the planned installation.

The VVO equipment at the Townsend Substation was commissioned in 2021 and the On/Off testing was completed in March of 2024. This VVO functionality has been running since the completion of the On/Off testing.

The VVO equipment at the Summer St. Substation was fully commissioned in 2022. The circuits supplied from the Summer St. substation, were operated in an abnormal configuration, due to a construction project at another substation, not related to the GMP, and therefore, the planned commencement of the On/Off testing was deferred until December of 2024. The On/Off testing was completed in September, 2025.

The commissioning of the VVO equipment at the Lunenburg substation was completed in 2024, and the On/Off testing was started in April of 2024 and completed in June of 2025.

The commission of the equipment at the West Townsend substation was completed in 2025 and the On/Off testing is started in June of 2025 and was completed in January 2026 for the purpose of evaluation by a third party.

Advanced Distribution Management System Investment Category

The Company has completed its planned ADMS deployment for the GMP. This includes the completion of the modelling and implementation of unbalanced load flow (UBLF) and testing and operation of VVO in ADMS for four substations (thirteen circuits). ADMS/VVO when enabled is setting all regulator bandcenters and controlling all capacitor banks on the circuit to minimize losses and system demand.

Communications Investment Category – Field Area Network

The Company is utilizing the AT&T FirstNet cellular network for its FAN supported by two fiber backhaul circuits for primary and backup network connectivity. At the end of 2022, the Company had installed and commissioned all network backbone infrastructure and 125 endpoint devices. The Company is now to a point where the expansion of the FAN consists of installing modems in the VVO equipment as it is installed in the field. Therefore, the Company began including FAN capital costs in the VVO project as opposed to reporting the FAN project as a separately .

Workforce Management Investment Category

The Company has completed development and testing of the Mobile Information Management System (MIMS) Lifecycle proposed by SSP Innovations. The MIMS solution was synchronized with the Company's GIS systems and is designed to perform electronic field inspections of assets and vegetation while also providing the ability to create workflows, assign and track work assignments, and estimate cost, labor and equipment associated with storm damage repairs and daily work orders. The project was expected to begin in late Q1 of 2020, delays resulting from the COVID-19 pandemic and again in 2022 due to a necessary upgrade to the Company's GIS system impacted the project timeline which was completed in Q1 of 2026.

Following the delays, the Project Team regrouped in late 2022 to reestablish the project with the vendor and started development of the solution in early 2023. Throughout 2023 significant work was conducted by the project team and SSP to prepare the Company's IT infrastructure and systems for installation of the application. In 2024 the solution was installed on the Company's development servers and completed activities including system configuration and initial system and user acceptance testing. Due to operating system upgrades and a newer version of the solution required, re-installation of the solution occurred in 2025 with additional training and full implementation to be completed by Q2 2026.

DER Mitigations

The project objectives were to implement overvoltage protection improvements on the 69 kV side of three distribution substations to mitigate the risk of ground-fault overvoltages resulting from distribution-connected DER sustaining the energization of the 69 kV system after the normal effectively-grounded utility transmission and sub-transmission sources have disconnected in response to line-to-ground short circuits. The implementations included modifications to substation and sub-transmission line surge protection, and the addition of voltage transformers and overvoltage relaying schemes where necessary.

The Company completed these ground-fault overvoltage protection implementations at two of these substations in 2024 (Canton Street and Sawyer Passway), and at the third substation in 2025 (Summer Street).

<u>Advanced Metering Infrastructure</u>

The Company filed its 2022-2025 Grid Modernization Plan on July 1, 2021. In this filing, the Company was required to file an AMI plan. The Company's plan consisted of a meter replacement to transition from TS2 to Gridstream PLX technology.

On June 29, 2022, the Company was notified Landis+Gyr would discontinue their Gridstream PLX technology. Landis+Gyr referenced supply chain challenges and the risk of obsolescing components that support PLC communications as the reasons for discontinuing this product. Landis+Gyr recommended a new communications technology using a combination of radio frequency and/or cellular. The Landis+Gyr transition plan identified June 2023 as the end-of-purchase for PLX endpoints and support for the powerline carrier system would continue until 2029.

The Company held several meetings with Landis+Gyr from July – November determine if there was a way to simply replace the communications technology (i.e. replace powerline carrier with RF mesh technology). It became apparent that this approach would not be available and the Company would be required to replace all meters as well as the communications technology prior to 2029.

At that point, the Company decided to RFP and go through a competitive bidding process for a new AMI system. The RFP was issued on December 22, 2022 with responses due March 1, 2023. The Company spent several months during 2023 evaluating vendor proposals and ultimately selected Landis+Gyr as the vendor for the replacement AMI system which consists of a new RF based field area network, a cloud-based software head-end system, and the replacement of all existing PLC electric meters.

The Company filed a petition with the Department (D.P.U. 24-54) to revise the scope of the original AMI project and obtain preauthorization of certain AMI investments in connection with the revised scope. On March 28, 2025 the Department issued an order (D.P.U. 24-54-A) approving this petition. The capital investments and O&M costs presented in this report represent the revised AMI project scope.

<u>Customer Engagement and Experience</u>

For the Customer Experience Management Solution project, the Company contracted with Systems & Software (existing CIS vendor) and launched the system in April of 2024. This system leverages an integrated web portal and mobile application. With the upgraded web portal, customers now have access to a number of usage analytics tools including interactive graphs containing weather data overlays, usage comparison features, resource links and marketing images designed to promote energy conservation, and enhanced usage download functionality. In addition, customers now have the option to enroll to receive service appointment reminders and payment reminders. In early 2025, enhanced outage alert functionality was enabled in the system to proactively alert customers of an outage affecting their service location and to provide real-time outage status updates. As electric customer meters are upgraded to Revelo AMI meters, the Company has worked to ensure customer access to register read data through their online accounts. Accessibility, digital payment, and security enhancements were also executed on the company portal in 2025. In addition, the Company initiated an effort to consolidate energy saving and conservation resources on their company website and developed tools to assist customers in navigating these options. The Company refers to these resources and tools as our Energy Navigator platform, which was launched in early 2026.

Data Sharing Platform

In November of 2022, the MA D.P.U. issued a Final Order on the second grid modernization plans filed by the EDCs directing the EDCs to convene a statewide stakeholder working group to address topics related to AMI implementation plans. In March of 2025, the MA D.P.U. filed a procedural memorandum requesting input on third-party access to customer AMI usage data and customer usage data sharing.

In February of 2026, the EDCs submitted, for Department approval, an AMI data access plan similar to the state-wide Multi-Use Energy Data Platform proposed in NH. The goal of this proposed centralized AMI data repository plan is to allow customer and third parties near-real time access to AMI data.

1.3 SUMMARY OF SPENDING (ACTUAL V. PLANNED SPENDING)

This section of the report summarizes the actual versus planned spending from a capital spending as well as an incremental O&M spending basis.

1.3.1 CAPITAL SPENDING (ACTUAL V. PLANNED SPENDING)

The "2022-2025 Plan" represents the planned spending in 2022 and the following years. The "2022-2024 Actual / 2025 Forecast" Plan Year represents the actual spending for 2022-2025. Table 1 below demonstrates the actual spending versus the plan.

Actual Capital Spending					
	2022	2023	2024	2025	**Total**
Monitoring and Control					
SCADA					
2022-2025 Plan	$625,000	$186,000	$218,000	$100,000	**$1,129,000**
2022-2025 Actual	$101,337	$208,870	$287,856	$22,541	**$620,604**
OMS Integration with AMI					
2022-2025 Plan	$155,000	$0	$0	$0	**$155,000**
2022-2025 Actual	$0	$0	$0	$0	**$0**
Volt VAr Optimization (VVO)					
2022-2025 Plan	$270,000	$675,000	$2,070,000	$2,400,000	**$5,415,000**

2022-2025 Actual	$274,171	$462,205	$596,348	$612,733	**$1,945,457**
Advanced Distribution Management System (ADMS)					
2022-2025 Plan	$400,000	$250,000	$175,000	$125,000	**$950,000**
2022-2025 Actual	$60,153	$101,731	$80,326	$2,988	**$245,198**
Field Area Network					
2022-2025 Plan	$198,000	$121,000	$285,000	$179,000	**$783,000**
2022-2025 Actual	$46,562	$0	$0	$0	**$46,562**
Workforce Management					
Mobile Platform Damage Assessment					
2022-2025 Plan	$50,000	$50,000	$50,000	$50,000	**$200,000**
2022-2025 Actual	$9,229	$63,212	$41,486	$91,090	**$212,757**
DER Integration					
DER Mitigations					
2022-2025 Plan	$289,000	$753,000	$0	$0	**$1,042,000**
2022-2025 Actual	$3,394	$91,629	$348,378	$165,249	**$608,650**
Advanced Metering Functionality					
AMI					
2022-2025 Plan	$2,345,532	$4,565,134	$3,977,770	$339,080	**$11,227,516**
2022-2025 Actual	$76,270	$0	$3,865,522	$5,923,041	**$9,864,833**
Customer Engagement					
Customer Engagement and Experience					
2022-2025 Plan	$241,000	$91,000	$0	$0	**$332,000**
2022-2025 Actual	$28,805	$18,350	$0	$0	**$47,155**
Data Sharing					
2022-2025 Plan	$466,000	$78,000	$0	$0	**$544,000**
2022-2025 Actual	$0	$0	$0	$0	**$0**
Total					
2022-2025 Plan	$5,039,532	$6,769,134	$6,775,770	$3,193,080	**$21,777,516**
2022-2025 Actual	$619,526	$1,079,668	$5,304,749	$6,800,052	**$13,803,995**

Table 1 – Planned Versus Actual Capital Spending

Note: The AMI costs included in table above includes the estimated cost of replacing the AMI system as presented to the Department in D.P.U. 24-54. The Company identifies the AMI information presented in this report as a variation from the previously approved AMI project in the 2022-2025 plan.

Overall, actual spending through 2025 was below the original 2022 – 2025 plan.

The OMS Integration with AMI project has been placed on hold due to the challenges associated with implementing a secure network for ADMS and the discontinuation of AMI PLX technology. Therefore, there was no spending on this project in 2025.

1.3.2 INCREMENTAL O&M SPENDING (ACTUAL V. PLANNED SPENDING)

The table below summarizes the incremental O&M spending identified in the plan compared to the actual and forecast spending. O&M spending in 2023 was lower than planned primarily due to delays in projects.

In the 2022-2025 Plan the licensing fees for the FAN modems were included in the Communications project. In 2022 - 2025 actual, these costs are included in the VVO and SCADA project as the modems are commissioned with the field equipment.

	Actual Incremental O&M Spending				
	2022	2023	2024	2025	**Total**
Monitoring and Control					
SCADA					
2022-2025 Plan	$0	$0	$0	$0	**$0**
2022-2025 Actual	$0	$0	$0	$0	**$0**
OMS Integration with AMI					
2022-2025 Plan	$0	$11,000	$11,000	$11,000	**$33,000**
2022-2025 Actual	$0	$0	$0	$ -	**$0**
Volt VAr Optimization (VVO)					
2022-2025 Plan	$5,000	$5,000	$5,000	$5,000	**$20,000**
2022-2025 Actual	$8,208	$18,080	$2,159	$ 2, 159	**$28,447**
Advanced Distribution Management System (ADMS)					
2022-2025 Plan	$174,000	$176,000	$177,000	$178,000	**$705,000**
2022-2025 Actual	$60,706	$ 106,133	$ 99, 105	$103,288	**$163,994**
Field Area Network					
2022-2025 Plan	$10,000	$10,000	$10,000	$10,000	**$40,000**
2022-2025 Actual	$10,000	$26,328	$26,453	$27,300	**$90,081**
Workforce Management					
Mobile Platform Damage Assessment					
2022-2025 Plan	$50,000	$50,000	$50,000	$50,000	**$200,000**
2022-2025 Actual	$0	$16,000	$0	$0	**$16,000**
DER Integration					
DER Mitigation					
2022-2025 Plan	$0	$0	$0	$0	**$0**
2022-2025 Actual	$0	$0	$0	$0	**$0**
Advanced Metering Functionality					
AMI					
2022-2025 Plan	$0	$0	$0	$0	**$0**

2022-2025 Actual	$0	$0	$0	$0	**$0**
Customer Engagement					
Customer Engagement and Experience					
2022-2025 Plan	$16,151	$91,000	$16,151	$66,000	**$189,302**
2022-2025 Actual	$16,151	$16,151	$16,402	$16,960	**$65,664**
Data Sharing					
2022-2025 Plan	$0	$0	$0	$0	**$0**
2022-2025 Actual	$0	$0	$0	$0	**$0**
Third Party M&V Evaluation					
2022-2025 Plan	$75,000	$75,000	$75,000	$75,000	**$300,000**
2022-2025 Actual	$10,193	$75,000	$21,902	$38,064	**$182,095**
Total					
2022-2025 Plan	$330,151	$418,000	$344,151	$395,000	**$1,487,302**
2022-2025 Actual	$105,258	$257,692	$149,635	$299,419	**$812,004**

Table 2 – Planned Versus Actual Incremental O&M Spending

Reference Tab 5a of the Company's D.P.U. Appendix 1 for plan year 2022-2025 O&M expenses.

2 PROGRAM IMPLEMENTATION OVERVIEW

The Company developed an organizational structure, project management and project approval and tracking process that rely mostly on existing employees and processes. Project teams have responsibility for implementing the grid modernization projects. These individuals are also the same individuals who are designing and implementing traditional investment projects. These individuals have a full understanding which projects are related to the GMP and which projects are not associated with the GMP.

The Company intends to leverage as much of its existing infrastructure and traditional investments as possible to further advance the grid. However, investments made outside of the GMP will not be included for cost recovery through the grid modernization proceedings. The Company believes this approach will help the Company to manage costs and result in an efficient implementation of the grid modernization investments. This approach will also allow the Company to differentiate between devices installed under the pre-authorized grid modernization investments and those installed under typical company investments. In some cases, when the Company does not have the experience or technical expertise, external resources will be required to assist with the design and implementation of GMP investments.

2.1 ORGANIZATIONAL CHANGES TO SUPPORT PROGRAM IMPLEMENTATION

This section of the report 1) describes the organizational changes that the Company has implemented to manage the implementation of the GMP, 2) describes the cost and performance tracking measures adopted, and details the project approval process.

The Company implemented an organizational structure for grid modernization beginning at the highest level of the Company. The senior level sponsors of the GMP implementation include the Chief Executive Officer, President, and Chief Financial Offer. This group provides general oversight and direction for the GMP plan implementation. The senior level sponsors have assigned overall oversight of the grid modernization program to the Vice President of Engineering.

The Company developed a cross-functional Steering Committee to provide guidance and oversight of the GMP implementation process. The chair of the Steering Committee is the Director of Grid Modernization. The Steering Committee includes representation from Engineering, Information Technology, Electric Operations, Regulatory, Customer Energy Solutions, Customer Operations, Plant Accounting, Finance and Budgeting and Legal. The Steering Committee provides detailed oversight for budget and implementation of the GMP investments, reporting and annual updates.

The Steering Committee implemented project teams responsible for the detailed design and project implementation oversight. The Steering Committee identified individual project team leads for the GMP investments. The Steering Committee also developed teams related to the tariff revisions, performance metrics, evaluation plan, cost recovery filing and the Grid Mod Annual Report.

The project leads are primarily focused on the design and implementation of their particular project. The project leads provide updates on their individual projects at the Steering Committee meetings as well as provide updates and data for this report.

2.2 COST AND PERFORMANCE TRACKING MEASURES ADOPTED

The Company decided that it would be most efficient to use the same budgeting and construction authorization approval process that is in use for all of its capital projects. GMP investments have been entered into the annual capital budget for review and approval. Each of the GMP investments will have its own construction authorization and/or its own CWO. The authorizations will follow the approval process described below.

Incremental O&M expenditures related to Grid Modernization will be budgeted and tracked through the Company's expense budget using established O&M budgeting procedures. The Company has filed a GMF to recover costs incurred on grid modernization projects in 2025. See D.P.U. 26-60.

2.3 PROJECT APPROVAL PROCESS

There are several layers of controls on spending. First, and perhaps most important, is the budget process. The capital budget represents the culmination of a lengthy planning process to identify and prioritize important needs, while ensuring that projects submitted for approval are the most cost-effective solutions to address those needs and are estimated appropriately. The budget proceeds through several rounds of review at multiple levels of the organization before concluding with review and approval by senior management, and by the Company's Board of Directors.

After the budget is approved, each project within the budget must be further authorized before spending can occur. This is a second step in the approval process, and occurs on a project-by-project basis. A construction authorization must be prepared and submitted for approval for each planned expenditure and each project in the budget, even though the budget has already been approved. Each authorization must be fully approved prior to the commencement of any work, except where an unforeseen emergency occurs that requires the work to be completed to ensure public safety or restore service to customers, in which case the authorization can be completed immediately following the work.

Every capital project requires an approved construction authorization. The approval routing for each construction authorization includes, but is not limited to, the Plant Accountant, the Department Manager, the Vice President with functional responsibility for the project, and the Senior Vice President of Electric Operations. Additional approvals may be required by one or more functional heads depending on the project and the functional areas affected by it. All authorizations over $50,000 also require the approval of the Vice President, Regulatory and Finance. In addition, all authorizations exceeding $500,000 must be approved by the Controller and the Chief Financial Officer. Plant Accounting is responsible for assigning the appropriate routing for each authorization and for validating the authorization and construction work order ("CWO") number once all managers have approved the authorization, whereupon expenditures may begin.

Each project and each construction authorization are assigned a Project Supervisor. The Project Supervisor is designated on the authorization form as it is routed for approval, and is typically the person who developed the scope and cost of the project, and who initiated the construction authorization for approval. In all cases, the Project Supervisor is the person responsible for managing the project and the person directly accountable for controlling the scope and cost of the project.

Changes in the field sometimes result in changes to the scope of a project already approved and underway. When this occurs, the Project Supervisor is required to submit a revised construction authorization reflecting the then current (revised) scope, including cost, before proceeding further with the project. The revised authorization must be resubmitted for approval in the same manner as the original authorization, with the additional approval of the Controller and Chief Financial Officer. The revised authorization must include a detailed description identifying the change in scope and the reasons for the change, and provide a detailed cost breakdown.

The budget and authorization processes recognize that project estimates are just that, "estimates." Invariably, a small number of projects will overrun the original estimate due to conditions in the field, increases in material costs and other factors. The Project Supervisor's responsibility is to manage the cost of each project to the original authorized spending amount. If the cost of the project exceeds the authorized amount by 15 percent and $5,000, a supplemental authorization must be submitted that includes a detailed description of the reasons the project exceeded its authorized amount. The supplemental authorization must be resubmitted for approval in the same manner as the original authorization, with the additional approval of the Controller and Chief Financial Officer.

All projects, whether budgeted or unbudgeted, must be approved and authorized before spending can occur. If a non-budgeted expenditure is required, a non-budget authorization must be prepared and all necessary approvals received. It is the responsibility of the applicable budget manager to ensure that non-budgeted expenditures are required to ensure a safe and reliable system for our customers. Non-budget authorizations must be submitted for approval in the same manner as the project would normally be authorized, with the additional approval of the Controller and Chief Financial Officer.

O&M expenditures also require approval prior to spending. The O&M budget proceeds through several rounds of review at multiple levels of the organization before concluding with review and approval by senior management, and by the Company's Board of Directors. Expenditures are tracked on a monthly basis. Each level of management has varying approval levels. Deviations from the budgeted amount require additional reporting and explanation. Grid Modernization expenditures will be tracked separately to ensure the costs are incremental in nature.

The Company has found that it beneficial to use the same approval processes for Grid Modernization as it uses for other projects. Grid Modernization projects are identified as such and tracked separately yet in the same manner as non-grid modernization projects.

3 IMPLEMENTATION BY INVESTMENT CATEGORY

This section of the report provides details for each GMP investment category at both the system and feeder level. In some cases, the investment is not implemented differently at the system as opposed to the individual feeder level. For instance, some software projects are implemented across the service territory at the same time and not on an individual feeder basis. The investment categories and project investments are identified in Table 3 below:

Investment Category	GMP Investment
Monitoring and Control	Supervisory Control and Data Acquisition
	OMS Integration with AMI
Volt/VAr Optimization	VVO LTCs VVO Voltage Regulators VVO Capacitor Banks VVO Remote Measurement Sensors
Advanced Distribution Management System	ADMS
	DERMS
Communications	Field Area Network
Workforce Management	Mobile Platform Damage Assessment
DER Integration	DER Mitigations
AMI	AMI System & Meter Replacement
Customer Engagement	Customer Engagement and Experience
Customer Engagement	Data Sharing Platform

Table 3 – GMP Investments by Investment Category

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 grid modernization plan investments and their progress toward meeting the Department's grid modernization objectives. The Companies along with Guidehouse expect the Massachusetts Grid Modernization Program Year 2025 Evaluation to be issued by July 1, 2026.

3.1 SYSTEM LEVEL NARRATIVE BY INVESTMENT CATEGORY

This section of the report identifies the progress made at the system level for each of the investment categories: it describes the project; provides a description of the work completed lessons learned, challenges and successes; provides actual versus planned implementation and spending; describes the performance of the implementation and deployment; describes the benefits realized as a result of the implementation; describes the capability improvement; provides key milestones.

Some of the projects in the GMP are closely tied together. For instance, a VVO system will not be successful without a FAN or ADMS. The Company is coordinating the projects in the table below so they can be implemented on the same portions of the system at the same time.

Investment Category	**GMP Investment**
Monitoring and Control	Supervisory Control and Data Acquisition
Volt/VAr Optimization	VVO LTC VVO Voltage Regulators VVO Capacitor Banks VVO Remote Measurement Sensors
Advanced Distribution Management System	ADMS
Communications	Field Area Network
DER Integration	DER Mitigations

Table 4 – GMP Project Schedules to be Coordinated

The Company's plan is to implement these projects on a substation by substation basis. For instance, the FAN, VVO, SCADA and ADMS projects were implemented at the same time or close proximity to each other. In order to facilitate this effort, the Company developed a ranking system to prioritize which substations provide the largest benefits to customers and should be completed first.

The Company developed a prioritization model shown in the table below using a weighted ranking system based upon the following items:

Weighting Factor	Measurement Category	Description
30%	Peak Demand	The VVO project provides the largest benefit to customers. In order to get the greatest benefit as soon as possible, the VVO system should be implemented on the circuits with the highest peak demand.
30%	Percent Substation Loading	This is a measure of the peak loading on a substation as compared to its rating. For instance, a substation that is reaching its rating may require a system improvement to alleviate the loading concern. The VVO project provides the opportunity to reduce peak demand and potentially defer investment in a system improvement.
20%	Number of Customers	This is a combined measure of reliability and customers gaining the benefit of Grid Mod investments. The substations serving the largest number of customers will allow more customers to begin receiving benefits of the GMP investments.
10%	Planning Level Voltage Concerns	Distribution planning is used to identify portions of the distribution system which may be approaching voltage limits as defined in planning guidelines. The VVO project would provide the opportunity to control the voltage and alleviate loading and potentially defer investment in a system improvement.

10%	Existing SCADA	In areas that already have distribution SCADA or may only need small modifications to achieve the required functionality may allow other functionality to be implemented more quickly.

Table 5 – Weighted Rankings for Prioritization Model

The Company's prioritized ranking system weighs the ability to reduce load evenly with the opportunity to defer system investments. These two aspects provide the largest potential monetizable benefits to customers. In comparison, the Company weighs the opportunity to reach as many customers as possible slightly less than the first two. This is still a very important aspect, but may not provide the largest benefit. Implementing a project in an area that serves a larger number of customers but does not experience loading concerns may not maximize the benefits. The Company ranks the last two factors evenly, as they both provide benefit to customers and should be included in the ranking system.

In each of the measurement categories, the highest weighted substation receives a score of 1. For instance, the substation serving the most customers receives a score of one (1) and the other substations are given a score that is proportionate to the maximum number[2]. This is repeated for each category. The score for each category is multiplied by the weighting factor and added together to give a total score for each substation. The substation with this highest score becomes the highest priority for implementing the projects. Table 6 provides the results of the calculations. The substations have been ordered from highest to lowest rank.

Substation	Number of Customers	Planning Level Voltage Concerns	Existing SCADA	Peak Demand	Percent Substation Loading	Rank
Townsend	0.43	0.64	1.00	0.58	1.00	0.72
Lunenburg	0.60	0.94	0.50	0.48	0.85	0.66
Summer Street	0.76	0.71	0.43	0.76	0.53	0.65
West Townsend	0.68	1.00	0.50	0.44	0.78	0.65
Beech Street	1.00	0.79	0.13	0.62	0.51	0.63
Pleasant Street	0.77	0.74	0.50	0.45	0.68	0.62
Princeton Road	0.21	0.63	0.38	1.00	0.46	0.58
Sawyer Passway	0.55	0.27	0.34	0.52	0.24	0.40
Canton Street	0.59	0.30	0.00	0.34	0.46	0.39
River Street	0.37	0.39	0.38	0.23	0.30	0.31
Nockege	0.24	0.74	0.00	0.11	0.49	0.30

Table 6 –Prioritization Model Scores

[2] For instance, if Substation A serves the greatest number of customers (i.e. 5,000 customers), Substation A would receive a score of 1. If Substation B serves 2,500 customers, Substation B would receive a score of 0.5.

3.1.1 MONITORING/CONTROL

The original Monitoring and Control investment category included two projects from the Company's GMP. The first project was to expand the coverage and functionality of Company's SCADA system. The second project was to further integrate OMS with the Company's AMI system. This second project was removed from the plan since the AMI system is now planned to be replaced and this functionality is inherent within the new AMI system.

The objective of the SCADA project has been to implement key SCADA functionality at all of the Company's substations. SCADA provides for the remote monitoring of conditions on the electric system and the remote control of equipment and functions by operating personnel or automation systems. The substation SCADA project is a component of the Company's Monitoring and Control program as part of its overall GMP, and is an enabling technology for other projects in the GMP including VVO and ADMS. In conjunction with other components of the Plan, it supports the GMP objectives of reducing the effects of outages and optimizing demand.

The implementation of SCADA at a substation typically involves the installation of a SCADA terminal unit at the site, the interconnection of the terminal unit with local devices and sensors, the establishment of communications between the terminal unit and the remotely-located SCADA Master system, and the associated programming to implement the desired SCADA functions.

At the start of the GMP, SCADA was already implemented to some extent at some of the Company's substations, and not at all at others. Furthermore, at many substations that had some level of existing SCADA capability, it was incomplete to the extent intended under the GMP. Therefore, this project is adding SCADA at those substations that do not presently have it, and expanding SCADA capabilities at other substations where the functionality may be incomplete.

Additionally, some of the substation devices that are necessary to provide the power system measurements for other projects (e.g. VVO) or that will otherwise be put under SCADA control were either absent or not suitable for this purpose (e.g. hydraulic reclosers, obsolete controls, etc.). Therefore, this SCADA project is also driving the replacement of that type of equipment and the installation of additional ancillary devices to better facilitate SCADA deployment.

3.1.1.1 Description of Work Completed

The Company has completed GMP-related SCADA implementations at all nine of the substations planned for in its GMP (Rindge Road, Townsend, Beech Street, Lunenburg, Nockege, River Street, Canton Street, Princeton Road and Pleasant Street).

3.1.1.2 Lessons Learned/Challenges and Successes

Further detailed design and SCADA functionality review identified certain equipment replacements and device additions which were not identified in the original GMP estimate. The replacements represent an increase in the overall cost proposals for the SCADA project. These replacements and additions have been necessary to achieve the levels of functionality and measurement requirements now established for the other grid modernization projects and metrics.

3.1.1.3 Actual vs. Planned Implementation and Spending

The original GMP plan for SCADA submitted in 2015, resulted in a levelized 10 year plan with an annual estimate of $100,000 per year or $1.0 million total. **Error! Reference source not found.** provides the spending for the the GMP term.

	2022		2023		2024		2025	
Year	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
Capital Costs	$625,000	$101,337	$334,405	$208,870	$640,000	$287,856	$32,955	$22,541
O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0
Total Costs	$625,000	$101,337	$334,405	$208,870	$640,000	$287,856	$32,955	$22,541

Table 7 – SCADA 2022-2025 Actual

The estimated annual spending for this plan is not as levelized as was conceived in the original GMP. This is due to the varying extent of SCADA implementation already existing at some substations, and the varying amount of replacements of related equipment and additions of ancillary devices.

3.1.1.4 Performance on Implementation/Deployment

The Company has completed all of its GMP-related substation SCADA implementations as of 2025.

3.1.1.5 Description of Benefits Realized as the Result of Implementation

As the SCADA projects are completed at each substation, the GMP estimates that the company will be able to save 10 minutes off of each whole-circuit outage. Additionally, the implementation of SCADA at each substation will support other GMP investments including ADMS and VVO.

3.1.1.6 Description of Capability Improvement

The completed SCADA deployment at each substation provides for the following functionality:

- Real time telemetry and historical interval data for the following measurements for each power transformer and circuit position:
    - Voltage
    - Current
    - Active and Reactive Power
    - Active and Reactive Energy
- Remote monitoring of substation bus status (live/dead)
- Remote monitoring and control of substation circuit breakers/reclosers
- Remote monitoring and control of substation transformer LTCs or bus regulators
- Remote monitoring and control of substation capacitor banks
- Ability to integrate with ADMS and VVO

3.1.1.7 Key Milestones

GMP-related SCADA implementations were completed at Princeton Road and Pleasant Street substations in 2025.

3.1.1.8 Feeder Level Narrative

The table below identifies the status of SCADA on a substation and circuit basis.

Substation	Circuits	Comments
Beech Street	1W1 1W2 1W4 1W6	LTC control & partial SCADA completed 2018 (non-GMP). Full SCADA completed in 2020 as Grid Mod project, incl.: (3) circuit terminals, (1) LTC control, (1) transformer meter, (1) capacitor bank.
Canton Street	11W11 11W12	LTC control & SCADA completed in 2024 as Grid Mod project, incl.: (2) circuit terminals, (1) LTC control, (1) transformer meter.
Lunenburg	30W30 30W31	Partial SCADA completed 2018 (non-GMP). Full SCADA completed in 2020 as Grid Mod project, incl.: (2) circuit terminals, (3) single-phase bus regulators, (1) transformer meter, (1) capacitor bank.
Nockege	20W22	Full SCADA placed into service in 2023 as Grid Mod project.
Pleasant Street	31W34 31W37 31W38	Partial SCADA completed 2018 (non-GMP). Full SCADA completed in 2025 as Grid Mod project, incl.: (3) circuit terminals, (1) LTC control, (1) transformer meter
Princeton Road	50W51 50W55 50W56	Partial SCADA completed 2018 (non-GMP). Additional SCADA completed in 2023 as Grid Mod project, incl.: (3) circuit terminals, (2) LTC controls, (2) capacitor banks. Full SCADA completed in 2025 as Grid Mod project, incl.: (2) transformer meters.
Rindge Road	35W36	Full SCADA placed into service in 2019 as Grid Mod project.
River Street	25W27 25W28 25W29	Pre-existing partial SCADA. Full SCADA completed in 2023 as Grid Mod project; incl.: (3) circuit terminals, (1) LTC control, (1) transformer meter.
Sawyer Passway	22W1 22W2 22W3 22W8 22W10 22W11 22W12 22W17	Pre-existing SCADA.
Summer Street	40W38 40W39 40W40	Pre-existing partial SCADA. Full SCADA completed in 2020 (non-GMP).

	40W42	
Townsend	15W14 15W15 15W16 15W17	Full SCADA completed 2020 as Grid Mod project, incl.: (4) circuit terminals, (1) LTC control, (1) transformer meter, (1) capacitor bank.
Wallace Road	1341	SCADA completed 2019 (non-GMP).
West Townsend	39W18 39W19	LTC control & SCADA completed 2018 (non-GMP).

Table 8 – SCADA Status by Circuit

3.1.2 VOLT/VAR OPTIMIZATION (VVO)

VVO is a proven means for utilities to save energy for customers and reduce system demand all while ensuring reliable service. It also can help integrate DERs, by controlling the voltage variations caused by DERs. The VVO project will deliver significant and measurable benefits for the Company and its customers, while creating platform capability to be leveraged in the future.

The scope of the project includes installing automated controls on all voltage and reactive power equipment on all distribution circuits. This includes controls of all capacitor banks, voltage regulators and transformer load tap changers (LTCs). In addition, voltage and current monitors will also be installed at strategic locations on the circuits. The operation of these control devices will be coordinated and optimized centrally through the ADMS. The communication between the ADMS and the VVO controls will be designed and installed as part of the FAN project. The design requirements of the VVO system will be coordinated with the plans of the ADMS, SCADA and the FAN.

3.1.2.1 Description of Work Completed

The equipment for all circuits emanating from four substations have been installed and commissioned. The "On/Off" evaluation testing using the ADMS control of the equipment for all four substations has been completed and the VVO functionality has continued to run in service since the completion of the testing. All commissioned equipment is currently operating under local automatic control. The equipment is communicating to the ADMS system. Materials for the fifth substation have been ordered, but due to lead times, are not expected to be installed until 2026. The Company plans to continue to incorporate the installation of controls on all circuits emanating from one substation per year, detailed below as part of the ESMP. Because of material lead time the ordering of material is planned two years prior to the planned installation.

3.1.2.2 Lessons Learned/Challenges and Successes

After the first year of installation and commissioning, the Company improved the process of setting the controls and commission testing. This new process was found to reduce the labor time and costs.

The Company is using a model-based system to implement VVO through the ADMS. The system utilizes a dynamic operating model of the system in conjunction with real time information from the field and runs this information through a complex optimization algorithm, within the ADMS, to optimize the performance of the distribution system. The system model and algorithm combined with remote field measurements and control enable the circuit to be optimized based upon minimizing power loss or demand while maintaining acceptable voltage profiles on each distribution circuit.

Working with the ADMS manufacturer, the Company has determined the best information to report from the field devices to perform the central analysis and control. Commissioning of the field devices revealed some unexpected results. The equipment controls originally did not operate as expected. Through commission testing and working with the manufacturer of the controls for the field equipment, setting templates have been developed for each type of equipment.

Through implementation of SCADA communication and control of the VVO equipment, the Company discovered a number of design flaws of the equipment as it operated to perform VVO functionality. The Company worked with the equipment manufacturer to correct and improve the design.

Through the On/Off testing and evaluation, it was determined that the VVO implementation occomplished approximately 1.7% energy savings to the customers and 1.4% in peak demand, mainly through the ability to reduce the system voltage. The change in Power Factor was negligible.

3.1.2.3 Actual vs. Planned Implementation and Spending

The table below demonstrates the actual versus planned implementation and spending. The Company experienced a delay in the deployment of VVO at Townsend substation due to the VVO algorithm in the ADMS software. The company worked collaboratively with the vendor to troubleshoot the VVO algorithm with the vendor providing updated algorithm code and the Company completing some initial testing. The algorithm was deemed successful late in 2022. The Company began on/off testing at the first substation in 2023 and continued the equipment installation and commissioning through 2025.

Year	2022		2023		2024		2025	
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
Capital Costs	$270,000	$274,171	$675,000	$462,205	$474,000	$596,378	$452,050	$612,733
O&M Costs	$5,000	$8,208	$5,000	$18,080	$18,500	$2,159	$2,159	$2,159
Total Costs	$275,000	$282,379	$680,000	$480,285	$492,500	$598,537	$454,209	$614,892

Table 9 – VVO 2022-2025 Actual

3.1.2.4 Performance on Implementation/Deployment

The installation and commissioning of field equipment has been complete at four substations. The testing of the central control of these devices and On/Off Testing has been completed at all four substations. The evaluation of the VVO performance was completed by a third party.

3.1.2.5 Description of Benefits Realized as the Result of Implementation

The VVO system operates by constantly trying to optimize voltage regulation (voltage regulators, LTCs and reactive compensation through switched capacitor banks). The VVO project is expected to reduce customer energy consumption by 2% and is expected to reduce system and circuit peak demand by a similar amount once VVO is fully implemented. This will directly benefit customers by reducing their electricity consumption and thereby reducing their bills. By installing additional voltage regulators, the voltage level of the regulators is set lower and the bandwidth is tighter, so even prior to the VVO being implemented, the system voltage is controlled at a lower level with reduced fluctuation. The Company started on/off testing in 2023 and continued to perform On/Off testing as substations were commissioned through 2025. The evaluation for the Townsend substation was complete in 2024. The evaluation for the Luneburg, Summer Street, and West Townsend substations was completed is 2025.

The evaluation completed in 2025, determined the following:

Measurement	Lunenburg	Summer Street	West Townsend	Aggregated Total
Annual Energy Savings	818 MWh (2.5%)	549 MWh (1.0%)	1340 MWh (3.7%)	2,707 MWh 2.0%)
Annual Peak Load Reduction	120 MWh (2.2 %)	238 MWh (2.2%)	183 MWh 3.4%)	541 kW (2.5%)
Reduction of Distribution losses (%)	15.06%	2.07%	0.34%	1.42%
Improvement in Power Factor	0.036 (3.9%)	0.005 (0.6%)	-0.01 (-1.9%)	0.0074 (0.89%)
Reduction of GHG Emissions (Metric tons CO_2))	152	103	251	506 tons CO_2

3.1.2.6 Description of Capability Improvement

There are three primary aspects to implementing a VVO program: communications, software intelligence and field equipment. A robust communications network is the foundation for a successful VVO program. The communications network described earlier in this report was designed to support the VVO program. The software intelligence is detailed as part of the ADMS project.

Voltage regulation refers to the management of circuit level voltage in response to the varying load conditions. There are two primary devices required to control the voltage on a distribution circuit: substation transformer LTCs and voltage regulators. The distribution management system uses input from voltage sensors across the system to adjust the voltage regulators and LTCs to keep the system voltage at a lower level and at a tighter bandwidth than without VVO. Capacitors are used for reactive power regulation, keeping the system power factor closer to unity.

3.1.2.7 Key Milestones

During the Grid Modernization Plan, the Company identified the existing field devices and controls that were needed to be installed in order to implement a VVO system. The table below lists the number of devices that were installed and commissioned per substation over the VVO project. After the equipment was installed and commissioned, the modeling in ADMS system was completed to enable the ADMS system to analyze the required actions. The installation and ADMS controls were then evaluated for approximately nine months, through On/Off testing. After the On/Off testing was complete, the system was left in service and considered "implemented"

Year installed	Year VVO Implemented	Substation	LTC	Volt Reg	Cap Bank	Monitors
2021	2024	Townsend	1	6	4	12
2022	2025	Summer Street	1	12	4	30
2024	2025	Lunenburg	0	25	4	28
2024	2025	West Townsend	1	11	3	14

Table 10 – VVO Field Equipment Installed

3.1.2.8 Feeder Level Narrative

The Company installed and commissioned VVO devices (regulators, capacitor banks, and monitoring sensors) for the Townsend, Summer St., Lunenburg, and West Townsend circuits. The VVO functionality is tested and functional in the ADMS system for all four substations. The On/Off evaluation testing for the Townsend was completed in 2024. The On/Off evaluation for Lunenburg was started in 2024 and was complete in 2025. The On/Off evaluation for Summer Street and West Townsend started and was completed in 2025. The following table provides a feeder by feeder view of when the voltage regulator controls, capacitor bank controls and the LTC controls will be replaced and voltage and energy monitors installed.

Substation	Circuits	Year Field Devices Commissioned	Year Fully Deployed with ADMS
Townsend	15W15 15W16 15W17	2022	2024
Summer Street	40W38 40W39 40W40 40W42	2023	2025
Lunenburg	30W30 30W31	2024	2025
West Townsend	39W18 39W19	2024	2025

Table 11 – VVO Schedule Through 2025

3.1.3 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM

The ADMS investment category included two projects for the Company's GMP. The first project was an ADMS project to allow for more advanced measurement and control of the distribution system. The second project was to implement a DERMS which would enable the Company to improve situational awareness and operational intelligence for DERs. This second project was moved from the 2022-2025 GMP to the Company's ESMP.

The ADMS project consists of upgrading the Company's current OMS to a full ADMS platform that includes unbalanced load flow (UBLF) analysis and VVO functionality, future distribution automation functionality such as automated fault location, isolation and service restoration (FLISR), and to serve as a platform for the future DERMS. The existing system integrations with GIS, CIS, OMS and SCADA were enhanced to provide the necessary technical information for ADMS to perform the functions described above.

As provided in the Company's plan, the implementation of the ADMS was primarily focused on integration with its existing OMS and GIS, its existing and planned SCADA capabilities, and the establishment of its VVO system.

3.1.3.1 Description of Work Completed

In 2021 the Company completed the ADMS/UBLF implementation for the first of its substations (Townsend) and three distribution circuits supplied from it. ADMS/VVO testing for this substation and its circuits began in 2022. Formal VVO performance testing out of this substation was completed in 2024.

In 2023 the Company completed the ADMS/UBLF implementation for a second substation (Summer Streeet) and its six distribution circuits, and began the ADMS/VVO testing for these. Formal VVO performance testing out of this substation was completed in 2025.

In 2024 the Company completed the ADMS/UBLF implementation for a third substation (Lunenburg) including its two distribution circuits, and a fourth substation (West Townsend) and its two distribution circuits, and began the ADMS/VVO testing for these. Formal VVO performance testing for one of these was completed in 2025, and was still ongoing for the other at the end of 2025 (completed in January 2026).

The Company also enabled and configured the Switch Order module in the ADMS in 2023. The Company plans to implement workflows around the ADMS Switch Order module in the future and not as part of the GMP.

In 2025 the Company began its initial DERMS implementation efforts as part of its ESMP instead of the 2022-2025 GMP term. The Company plans to integrate its utility-owned DER facilities for the testing of DERMS functionality in the 2026 to 2027 timeframe, with the intent of having DERMS-supported services available to customer-owned facilities in 2028.

3.1.3.2 Lessons Learned/Challenges and Successes

The majority of 2025 was spent performing ADMS/UBLF and ADMS/VVO analysis and testing for the substations and circuits that have been implemented up to this time, as well as transitioning facilities with pre-existing SCADA functionality into the new ADMS/SCADA system.

3.1.3.3 Actual vs. Planned Implementation and Spending

The table below provides the actual versus planned implementation and spending.

Year	2022		2023		2024		2025	
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
Capital Costs	$400,000	$60,153	$250,000	$101,731	$175,000	$80,236	$125,000	$2,988
O&M Costs	$174,000	$60,706	$176,000	$98,333	$177,000	$99,105	$178,000	$103,288
Total Costs	$574,000	$120,859	$426,000	$200,064	$352,000	$179,341	$303,000	$106,276

Table 12 – ADMS 2022-2025 Actual

3.1.3.4 Performance on Implementation/Deployment

This project began in 2019. The Company implemented an ADMS test system and modelled and implemented ADMS/UBLF for one substation and three circuits in 2020. The implementation of the production system and the modelling of the initial substation and three circuits were completed in 2021. ADMS/VVO testing of the same substation and three circuits was completed in 2022. Implementation of ADMS/UBLF and ADMS/VVO for one additional substation and six circuits and the deployment of the Switch Order module in ADMS occurred in 2023. ADMS/UBLF and ADMS/VVO was implemented for two other substations in 2024.

3.1.3.5 Description of Benefits Realized as the Result of Implementation

The UBLF and VVO functionalities, plus the inclusion of SCADA functionality, within the new ADMS have been successfully implemented and utilized. The SCADA additions under the M&C portion of the GMP have all been incorporated into the new ADMS/SCADA function (refer to **Error! Reference source not found.** for the associated benefits for the M&C SCADA project). The UBLF and VVO functions in the new ADMS have been successfully applied to four (4) substations with thirteen (13) corresponding distribution circuits (refer to **Error! Reference source not found.** for the associated benefits for the VVO project).

3.1.3.6 Key Milestones

All key milestones for the ADMS project have been achieved for the 2022-2025 GMP term, including the 2025 milestone for implementation of ADMS/UBLF and ADMS/VVO for the circuits out of West Townsend substation.

The milestones for the DERMS project have been moved from the 2022-2025 GMP to the Company's ESMP.

3.1.4 COMMUNICATIONS

Prior to the Grid Modernization efforts, the Company's communication system consisted of powerline carrier AMI system, and a combination of wireless (cellular) and land-line telecommunications services for the existing SCADA communications. The Company is installing a Field Area Network (FAN) capable of supporting the functionality identified as part of the plan.

This project consisted of installing a FAN, including communications between collectors and endpoint devices (meters and distribution devices), and backhaul communications from collectors at each substation to the central office. In the context of the modern grid, communications are the glue that makes it possible for all parties to interact and share information. The FAN will handle data traffic between distribution and grid edge devices and centralized information and operational systems. The FAN will be used by most of the modern grid systems that the Company implements. These will include advanced metering and TVR, distribution automation and DER management.

3.1.4.1 Description of Work Completed

The Company is utilizing the AT&T FirstNet cellular network for its FAN supported by two fiber backhaul circuits for primary and backup network connectivity. At the end of 2022, the Company has installed and commissioned all network backbone infrastructure and 53 endpoint devices.

3.1.4.2 Lessons Learned/Challenges and Successes

The Company had originally developed separate project teams for each grid modernization investment. Throughout the early stages of the process, the Company has learned that each of the investments are so closely tied together that a common schedule has now been created for the FAN, ADMS, VVO and SCADA. Similarly, now that the FAN backbone has been installed it has been realized that additional FAN investments would be limited to the expansion of VVO. Therefore, it has been decided that all additional modem installations and associated capital costs would be included and tracked in the VVO project.

3.1.4.3 Actual vs. Planned Implementation and Spending

As previously described, the Company originally considered the addition of future endpoint devices associated with VVO to be part of the FAN project. However, the Company is now considering incremental endpoint devices to be associated with VVO and updated its estimates and project plan to coincide with SCADA and the VVO projects.

	2022		2023		2024		2025	
Year	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
Capital Costs	$198,000	$184,380	$0	$0	$0	$0	$0	$0
O&M Costs	$10,000	$26,328	$27,118	$26,650	$0	$26,453	$0	$27,300
Total Costs	$208,000	$210,708	$27,118	$26,650	$0	$ 26,453	$0	$27,300

Table 13 – FAN 2022-2025 Actual

3.1.4.4 Performance on Implementation/Deployment

To date, the Company has installed and commissioned all network backbone infrastructure and 127 endpoint devices for VVO are now connected to the FAN. Future expansion of the FAN is expected to be largely limited to the addition of new endpoint devices associated with VVO and will be continued to be tracked as part of the VVO project implementation.

3.1.4.5 Description of Benefits Realized as the Result of Implementation

A FAN is an enabling technology that would provide the Company with the communications backbone to install many of the grid modernization initiatives being considered. The installation of a FAN without any of the other programs does not result in any monetizable benefits. However, the VVO system cannot provide the benefits identified without a FAN.

3.1.4.6 Description of Capability Improvement

In the context of the modern grid, communications are a foundational technology that makes it possible for systems, operators and stakeholders to interact and share information. The FAN handles data traffic between distribution, grid edge devices, centralized information and operational systems. Key Milestones

3.1.5 WORKFORCE MANAGEMENT

The Company's GMP includes a workforce and asset management program aimed to improve performance of the Company following major events. One project identified for the program includes a mobility platform for storm damage assessment and asset inspections integrated with a work order process to improve situational awareness and the speed of restoration. This Mobile Platform Damage Assessment Tool will help the Company to make quicker, better-informed decisions and is aimed to ensure operational efficiency and maintain strong restoration performance.

This project is to implement a Mobile Platform Damage Assessment Tool to make quicker, better-informed decisions to ensure operational efficiency and maintain strong restoration performance by significantly reducing the amount of time for field information to be relayed. This solution integrates with existing systems and allow for faster and more accurate situational awareness.

3.1.5.1 Description of Work Completed

The Company had researched and evaluated various applications that will expedite damage data acquisition, develop fasters ETR's, enhance overall situational awareness and produce more efficient work packages that will, in turn, expedite the overall restoration. The project team developed an RFP and received proposals from 13 vendors. The project evaluation team was comprised of various company employees who have responsibilities either during routine or emergency times for processes and activities related to damage assessment and inspection including key members from the Electric Operations, Engineering, and IT departments as well as other employees who have emergency assignments related to Damage Assessment.

An initial screening process was used to separate the proposals into three tiers. Tier 1 vendors meet or exceed requirements set forth and have been contacted for a demo of their product. Tier 2 vendors may meet most of the requirements or require additional development but will still be considered. Tier 3 vendors either do not meet all requirements or have other constraints that may affect their ability to provide a suitable solution. The evaluation criteria developed for this project and vendors consisted of a combination of many technical and operational requirements and features.

Technical and security requirements for the application were provided by IT staff based on current requirements and restrictions while the Operational requirements were developed by key operational personnel familiar with the process. Each vendor meeting at least the minimum requirements will be considered for a series of product demonstrations. An evaluation model was developed to rank the vendors that were initially categorized in Tier 1.

The following criteria were evaluated by the project team:

Technical Requirements
Solution is compatible with android, iOS and windows operating systems
Solution has offline caching or other capabilities for loss of service
Solution is able to integrate with the desired applications for data (primary GIS and/or OMS)
Solution meets minimum requirements for data privacy and security
Solution has a separate testing and live portal capabilities
Bidder has provisions for ensuring the continuity of their solution and services (backup and data retention)
Solution complies with all access and permissions requirements (single sign on, user approvals)
Solution is cloud based leveraging major cloud based service
Operational Requirements
Bidder is able to provide 24/7 support services for solution including during emergencies/holidays
Solution is able to geo-fence/geo-tag incidents into groups
Solution has transactional history (audit logging) and can provide such reports
Field Collection - Solution has user-friendly field collection capabilities on mobile devices
Data Manipulation - Solution can analyze data (for ETRs), segment as required and be manually manipulated
Data Exportation - Solution can export specific data as needed to produce work packages and other assignments (i.e. Environmental or Vegetation work)
Data Reporting - Solution can provide standard and ad hoc reports on information as required
User training - System should have a user-friendly interface requiring minimal training time
Dashboard view - Solution contains a dashboard style desktop user interface for back office use
General Bidder Qualifications
Bidder appears to be qualified, competent and experienced in providing the services requested.
Bidder has expressed their ability to meet schedule.
Bidder has experience with utilities and/or industry
Bidders pricing is competitive and is in line with project estimates and specifications

Table 14 – Mobile Platform Damage Assessment Evaluation Criteria

After the initial review and evaluation, several vendors were invited to provide a presentation on their proposal so that the project team could gain a clearer understanding of their proposal and have any questions answered. Following the vendor presentations, the evaluation matrix was updated.

After several meetings and weeks of deliberation by the project team, it was ultimately decided that the best solution was the MIMS Lifecycle proposed by SSP Innovations. The MIMS solution will be synchronized with the Company’s GIS systems and is designed to perform electronic field inspections of assets and vegetation while also providing the ability to create workflows, assign and track work assignments, and estimate cost, labor and equipment associated with work orders. The Company completed review of the statement of work and contract documentation and began this project in late Q1 of 2020. The kickoff of this project was delayed initially by the COVID-19 pandemic and then again in 2022 by a necessary version upgrade needed to the Company's GIS system.

The project team regrouped in late 2022 to reestablish the project with the vendor and started the implementation of the solution in early 2023. Throughout 2023 significant work was conducted by the project team and SSP to prepare the Company's IT infrastructure and systems for installation of the application which began in Q1 of 2024. In 2024 efforts were completed to install the solution onto the Company's development servers and configure and test the application. Due to operating system upgrades (windows 11) by the Company and significant upgrades and re-versioning of the solution (MIMS and Lifecycle) re-installation of solution is required including user acceptance testing, training and full implementation which was completed by Q2 of 2026.

3.1.5.2 Lessons Learned/Challenges and Successes

Throughout this project, the Company has learned that mobile damage assessment is just one of the functionalities that this software platforms can provide. Other functionality includes asset management, inspections, and other workforce management tools with several proposals including many of these features included within their products. The Company is interested in additional functionality in the future and has included the additional functionality available from the vendor offerings during their evaluation.

The timeline for this project was also significantly delayed due to COVID-19, planned upgrades to connected systems/servers, and changes to the Company's device and security requirements all impacting resource availability. As delays occurred, continuous project reviews and resource adjustments were needed to support project activities and successfully configure, test and implement the solution.

3.1.5.3 Actual vs. Planned Implementation and Spending

The project team has identified a cost increase in this project. The increase in cost is primarily due to the platform nature of the vendor products. The platform approach will provide the Company with the ability to implement future functionality if so desired (such as: mobile inspections, redline, asset management, etc.).

	2022		2023		2024		2025	
Year	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
Capital Costs	$50,000	$9,228	$28,835	$63,213	$50,000	$41,486	$50,000	$91,090
O&M Costs	$50,000	$0	$16,000	$0	$16,000	$0	$16,000	$0
Total Costs	$100,000	$9,228	$44,835	$63,213	$66,000	$41,486	$66,000	$91,090

Table 15 – Mobile Platform Damage Assessment 2022-2025 Actual

3.1.5.4 Performance on Implementation/Deployment

The Company completed its review of the statement of work and execution of contract documentation and begin this project in January of 2021. Due to previously mentioned project delays, development began in 2022 with significant progress made through 2023 to 2025, and final project completion in Q2 2026.

3.1.5.5 Description of Benefits Realized as the Result of Implementation

The application will have several benefits related to Operations and Planning including the ability to confirm, validate and document predicted devices leading to a greater accuracy of affected customer counts, outage causes and times of restoration. Field damage assessment information will also allow work orders to be tied to actual damage or repair work geographical areas and will also provide the company with faster field information to better estimate and identify the types and amounts of specific resources needed and better identify when resources will no longer be needed. The Plan estimated that this is expected to save on average 15 minutes per outage during a major event.

3.1.5.6 Description of Capability Improvement

The mobile platform damage assessment system will be an application-based system that will replace existing paper-based damage assessment and inspections presently used by the Company. This system will allow damage to be collected on the mobile application including the location, the type of damage and pictures. This data will automatically be transferred back to the back-end system portal in the office where ETRs and work packages can be developed, issued for repair, and tracked until completion.

The following capabilities are technical requirements for the mobile platform damage assessment application.

1. Data collected by the platform must be fully accessible via a documented application programming interface (API).
2. The platform must be capable of rendering output in a device agnostic, fully responsive manner, compatible with all major mobile, laptop and desktop devices
3. The platform must be capable of high availability, redundancy, high-capacity storage and industry standard security and compliance
4. The platform must have the ability to consume data from legacy applications
5. The platform must have documented APIs allowing the Company to build its own connectors
6. The platform must support direct integration with GIS
7. The platform must support the ability to capture, store and display rich media content such as photos, video and audio files.
8. The platform must support the ability to work offline / without real time connectivity to the internet
9. The platform must support offline mapping
10. The platform must support integration with Active Directory for Single Sign On
11. The platform must include the ability to capture GPS coordinates and geo tag records and collected assets with this data
12. The platform should have no cap on the number of applications or the number of records that can be collected by a given application
13. The platform must support, at a minimum, two discreet environments for testing and production
14. The platform must support electronic signature capture
15. The platform must include audit logging capabilities to capture transactional history
16. All Systems that Handle Confidential Information must encrypt the data that include Confidential Information in transit using algorithms and key lengths consistent with the most recent NIST guidelines.

17. The initial application built on this platform will be for Unitil's Damage Assessment system. However, there are a number of additional areas wherein real time information exchange would result in more effective work flows. Future applications may include (but are not limited to): Asset inspections, Mobile Workforce Management, Mobile Work Order Management and Outage Management

3.1.5.7 Key Milestones

The Company has executed contract documentation for the project and began working with SSP to develop the solution in January 2021. Solution development was completed throughout 2022-2023 and started the implementation of the solution in early 2025. Throughout 2023 and 2024 significant work was conducted by the project team and SSP to prepare the Company's IT infrastructure and systems for installation of the application and test an initial solution. In early 2025, the Company was able to test functionality of the MIMS and Lifecycle solution on its development servers in preparation for installation of the upgraded solution expected in Q3. Due to required upgrades to both the SSP MIMS application and Company devices/operating systems, reinstallation of the solution was completed with additional testing in Q4 of 2025. Full implementation of the system was completed in Q1 of 2026 with additional use and evaluation activities planned for Q2 and Q3.

3.1.6 DER INTEGRATION

As the proliferation of DER on electric distribution systems increases to levels approaching that of the local distribution loads, challenges caused by reverse power flow and sustained energization become more prevalent. These challenges include adverse impacts on voltage regulation, short-circuit protection and overvoltage protection. The project objectives are to implement overvoltage protection improvements on the 69 kV side of several distribution substations to mitigate the risk of ground-fault overvoltages resulting from distribution-connected DER sustaining the energization of the 69 kV system after the normal effectively-grounded utility transmission and sub-transmission sources have disconnected in response to line-to-ground short circuits. The implementations include modifications to substation and sub-transmission line surge protection, and the addition of voltage transformers and overvoltage relaying schemes where necessary.

The project objectives were to implement overvoltage protection improvements on the 69 kV side of three distribution substations to mitigate the risk of ground-fault overvoltages resulting from distribution-connected DER sustaining the energization of the 69 kV system after the normal effectively-grounded utility transmission and sub-transmission sources have disconnected in response to line-to-ground short circuits. The implementations included modifications to substation and sub-transmission line surge protection, and the addition of voltage transformers and overvoltage relaying schemes where necessary.

3.1.6.1 Description of Work Completed

The Company completed these ground-fault overvoltage protection implementations at two of these substations in 2024 (Canton Street and Sawyer Passway), and completd the implementation at the third substation in 2025 (Summer Street).

3.1.6.2 Lessons Learned/Challenges and Successes

The DER mitigation project is a continuation of projects that the Company has completed at other substations. The company has learned over the years that these projects are successful at providing the protection required for reverse power conditions on the system.

3.1.6.3 Actual versus Planned Implementation and Spending

The table below provides the actual spending for the GMP term.

	2022		2023		2024		2025	
Year	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
Capital Costs	$289,000	$3,394	$715,768	$91,629	$863,000	$348,378	$163,293	$165,249
O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0
Total Costs	$289,000	$3,394	$715,768	$91,629	$863,000	$348,378	$163,293	$165,249

Table 16 – DER Mitigations 2022-2025 Actual

3.1.6.4 Description of Benefits realized as the Result of Implementation

The implementation of the overvoltage protection improvement projects at these substation decreases the risks of damage caused by ground-fault overvoltages on the 69 kV system due to DER on the distribution systems out of these substations.

3.1.6.5 Key Milestones

The overvoltage protection improvements were completed at Sawyer Passway and Canton Street substations in 2024, and were completed at Summer Street substation in 2025.

4 PERFORMANCE METRICS

In D.P.U. 12-76-B, the Department of Public Utilities (the "Department") directed the Companies to include in their GMPs metrics that track the implementation of grid modernization technologies and systems.

Each of the Companies filed a GMP that included a list of proposed statewide and company-specific infrastructure metrics. On May 10, 2018, the Department issued its Order regarding the individual GMPs filed by the Companies. In approving the metrics, the Department found that the purpose of the metrics will be to record and report information: the metrics will not, at present, be tied to incentives or penalties. D.P.U. 15-120/15-121/15-122, Order at 197. The Department ordered the Companies to establish baselines by which the grid-facing performance metrics will be measured against and to file them within 90 days of the Order. Id., at 203. To assist in the development of these baselines, the Department directed each of the 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. Additionally, the Department directed the Companies, when developing the proposed baselines to use, to the extent possible, information reported in the annual service quality filings, as well as other publicly available information. Id.

As part of its decision regarding the Companies' GMPs, the Department determined that additional work was needed to develop metrics that appropriately track the quantitative benefits associated with pre-authorized grid-facing investments, and progress toward the Grid Modernization objectives. Id., at 95-106.

On August 15, 2018, the Companies filed the proposed performance metrics as required by the Department following its approval of the Companies' modified GMPs. Each Company also filed baseline and target information for the statewide and Company-specific infrastructure metrics approved by the Department. D.P.U. 15-120/15-121/15-122 at 198-201.

The Department issued a Memorandum that set out required revisions to the August 15, 2018 performance metrics, and directed the Companies to develop additional performance metrics ("Metrics Revision Memorandum"). The Metrics Revision Memorandum set April 2, 2019, as the deadline for the Companies to file the revised and new performance metrics, with initial comments on the Companies' filing due on April 16, 2019, and reply comments due on April 23, 2019. Consistent with the directives contained in the Metrics Revision Memorandum, the Companies provided the required revisions to the initial set of performance metrics, as well as the new metrics required by the Department.

On October 7, 2022, the Department issued Order A which addressed the Companies' proposed continuing grid-facing investments. On November 30, 2022, the Department issued Order B which addressed the Companies proposed new grid-facing investments and AMI investments. Order A approved revised performance metrics for certain continuing investments. (Id. 102-104). The Department also noted that certain grid-facing performance metrics applicable to the continuing investments may need to be refreshed or revised. Order B at 324 citing Order A at 104. Additionally, Order B declined to approve new grid-facing and AMI performance metrics. (Id. 324). Consistent with the Department's directives, on November 7, 2022, the Companies submitted a compliance filing with updates to the stamp approved performance metrics.

On January 27, 2023, the Department requested comment and further proposals from the parties on performance metrics for both grid- and customer-facing investments. See D.P.U. 21-80/D.P.U. 21-81/D.P.U. 21-82, Hearing Officer Memorandum (January 27, 2023). During multiple rounds of comments, the Companies jointly submitted further comments on existing metrics and new grid-facing investments, as well as proposed additional new metrics and a reporting template for customer-facing investments. Additionally, the Companies' proposals addressed metrics and data reporting proposed by intervenors. Multiple intervenors submitted comments in response to the Department's January 27, 2023 Memorandum and to the Companies' and other intervenor proposals. On June 28 and June 29, 2023, the Department held technical sessions to address the performance metrics proposals and comments received. On November 9, 2023 the Department issued a memorandum providing guidance to the EDCs on performance metrics, and annual and evaluation reporting associated with their grid modernization plan investments. The November 9 Memo also directed the EDCs to file, for informational purposes, an evaluation plan for the Companies' second term grid modernization investments. On February 7, 2024, the EDCs filed evaluation plans developed by Guidehouse with respect to investments in Advanced Distribution Automation; Advanced Distribution Management System/Advanced Load Flow; Distributed Energy Resources Management System Evaluation Plan; Monitoring and Controls; Volt-VAR Optimization; and Workforce Management. The Companies submitted 2023 Evaluation Reports for Advanced Distribution Automation, Advanced Distribution Management

System/Advanced Load Flow, Communications, Monitoring and Control, and Volt-Var Optimization prepared by Guidehouse on June 28, 2024.

The Company has included the 2025 Grid Modernization Annual Report Template as Appendix 1 to this report.

4.1 STATEWIDE INFRASTRUCTURE METRICS

The following statewide infrastructure metrics have been approved by the Department. In some cases, the Company is able to provide quantities for the proposed metrics. However, in some cases the information is not able to be provided without the installation of specific equipment used for measurement and verification.

4.1.1 GRID CONNECTED DISTRIBUTED GENERATION FACILITIES

One of the primary objectives of grid modernization is to facilitate the interconnection of DER and to integrate these resources into the Company's planning and operations processes. This statewide infrastructure metric will quantify the DER units connected to the system on a circuit level and substation level basis. It is important to note that DER developers' decisions regarding DER interconnection may be influenced by tax incentives, subsidies, costs, and availability of the technology, which, in turn, will influence these metrics. Reference Tab 3 Feeder Status in Appendix 1 - D.P.U. Template for the breakdown of grid connected distributed generation facilities interconnected. The Company continues to make considerable progress in connecting DERs to the system. The Company is challenged in some areas where the DER capacity is creating reverse power flow and protection challenges. The Company's DER Mitigation project should alleviate the concern on those specific substations.

4.1.2 SYSTEM AUTOMATION SATURATION

This metric measures the quantity of customers served by fully automated or partially automated devices. The terms "fully automated" and "partially automated" refer to feeders for which the Company has attained optimal or partial, respectively, levels of visibility, command and control, and self-healing capability through the use of automation, as intended in the GMP.

4.1.2.1 Assumptions

Baseline saturation rate was calculated based on what existed on the system as of the December 31, 2017. Ideally, over time this metric will decrease based on GMP installed devices since the metric is calculating the number of customers per device installed. As more devices are installed the metric decreases. Customers that can benefit from multiple devices are counted just once for purposes of this metric. The installations are not limited to the main line infrastructure and include no-load lines and DSS lines.

4.1.2.2 Classification of Grid Modernization Devices

The following table 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/Protector 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			

Table 17– Classification of Grid Modernization Devices

4.1.3 Calculation Approach

As more automation is installed pursuant to Unitil's GMP, the results of this metric will be reduced.

Metric:

$$\frac{\text{Customers Served}}{\text{Fully Automated Device} + 0.5*(\text{Partially Automated Device})}$$

4.1.4 Results

The system automation saturation result at the end of year 2025 was calculated at 268.8 customers per automated device. This equates to a 1.9% improvement from the prior year. Reference Appendix 2 for the substation and circuit level detail.

4.1.5 NUMBER/PERCENTAGE OF CIRCUITS WITH INSTALLED SENSORS

This metric measures the total number of electric distribution circuits with installed sensors, which will provide information useful for proactive planning and intervention. The installation of sensors provides the means to enable proactive planning and measure a number of 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.

4.1.5.1 Assumptions

The base-line for this metric is all pre-existing sensors installations on distribution circuits and substation circuit terminals as of December 31, 2017.

4.1.5.2 Calculation Approach

This infrastructure metric measures the percent of distribution circuits that have sensors installed, which should increase as sensors are deployed.

4.1.5.3 Results

The baseline and results for the number and percentage of circuits with installed sensors. The table below summarizes the results.

	2017 Baseline	2025 Actual
Total number of Substations/Transformers	13	13
Total number of Substations/Transformers with Sensors	13	13
% of Substation/Transformers with Sensors	100%	100%
Total number of Circuits	45	42
Total number of Circuits with Sensors	34	42
% of Substation/Transformers with Sensors	75.5%	100%

Table 18 – Number/Percentage of Circuits with Installed Sensors

Appendix 3 provides the details behind this calculation.

4.2 COMPANY SPECIFIC INFRASTRUCTURE METRICS

The following company-specific infrastructure metrics have been approved by the Department. In some cases, the Company is able to provide baseline and target quantities for the proposed metrics. However, in some cases the baseline is not able to be provided without the installation of specific equipment used for measurement and verification.

4.2.1 NUMBER OF DEVICES OR OTHER TECHNOLOGIES DEPLOYED

The metric measures how the Company finished in comparison with its GMP from an equipment and/or device standpoint.

4.2.1.1 Assumptions

The number of devices for each investment are determined and/or updated from the initial GMP. The number of devices installed are compared to the total number of devices planned by circuit for each investment.

The Company notes that its GMP did not include a significant amount of detail. The Company developed detailed designs and detailed plans for each investment area. The estimated costs and number of devices were updated as the detailed designs were completed.

4.2.1.2 Calculation Approach

The following information was tracked and reported per 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

4.2.1.3 Results

Some of the investments identified are software projects, which are listed as a single technology to deploy. OMS Integration with AMI and Mobile Platform Damage Assessment will be implemented across the service territory at the same time.

The table below is used to summarize the results of this metric.

Grid Modernization Investments	Number of devices or other technologies deployed	Total number of devices planned	Percent – Number of devices installed / total number of devices planned
Monitoring and Control			
SCADA[3]	22	22	100%
Volt/VAr Optimization			
VVO Capacitor Banks[4]	15	15	100%
VVO Voltage Regulators	54	54 [5]	100%
VVO LTCs[6]	3	3	133%
Line Sensors[7]	81[8]	84 [9]	96%
ADMS			
ADMS	6	14	43%
Communications			
Field Area Network	127[10]	127	100%
Workforce Management			
Mobile Platform Damage Assessment[11]	0	1	0%
DER Integration			
DER Mitigation	4	4	100%
AMI			
AMI Replacement	0	0	0%
Customer Engagement			
Customer Engagement and Experience	1	1	100%
Data Sharing	1	1	100%

Table 19 – Quantity of Devices by Investment

4.2.2 Lessons Learned/Challenges and Successes

The Company has completed the 2022-2025 GMP. Most completed 100% of the planned installations.

[3] SCADA quantities listed here are the number of circuits with Grid Mod devices that include SCADA.
[4] VVO Capacitor Banks includes capacitor banks in substations as well as on distribution
[5] Due to circuit reconfiguration 3 regulators were removed from previous plan
[6] LTC's listed are specific to VVO implantation. These do not include the SCADA installation preparing for VVO.
[7] Sensors not included as a specific project but required for VVO to effectively operate
[8] The installation of three sensors are ties with future substation and are deferred to the future substation project.
[9] Due to circuit reconfiguration 6 sensors were removed from plan
[10] This is the number of end device antenae
[11] Mobile Platform Damage Assessment is a software project.

4.2.3 ASSOCIATED COST FOR DEVELOPMENT

This metric measures the associated costs for the number of devices or technologies installed and and compared to the estimated cost of the 2022-2025 GMP.

4.2.3.1 Assumptions

The cost of devices or technologies for each investment was updated from the initial GMP. The cost of devices installed is compared to the total cost of devices planned by circuit for each investment. Where the technology is a central technology used in multiple states, the costs listed are those allocated to use for Massachusetts.

4.2.3.2 Calculation Approach

The following information will be tracked and reported upon per investment 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

Grid Modernization Investments	Cost of devices or other technologies deployed[12]	Total planned costs	Percent – Cost of devices installed / total cost of devices planned
Monitoring and Control			
SCADA	$1,519,869	$1,530,283	99%
Volt/VAr Optimization	$5,100,305	$ 7,451,136	
ADMS and DERMS	$579,907	$950,000	61%
Communications			
Field Area Network	$382,380	$ 674,000	57%
Workforce Management			
Mobile Platform Damage Assessment	$311,520	$286,304	109%
DER Integration			
DER Mitigation	$608,650	$958,240	64%
AMI			
AMI Replacement	$9,864,833	$11,227,516	88%

[12] This accumulative cost of devices in the 2022-2025 plan and includes costs prior to 2022 if applicable.

Customer Engagement			
Customer Engagement and Experience	$72,660	$1,212,000	6.0%
Data Sharing	$0	$544,000	0%
Plan Total	$ 18,440,124	$24,833,479	74%

Table 20– Total Capital Costs of Devices Planned

4.2.4 Lessons Learned/Challenges and Successes

The Company has completed the 2022-2025 Grid Modernization Plan. The actual cost of one project was greater than the planned amount. That project (Mobile Platform Damage Assessment) was not completed prior to the end of 2025, and will not be included in the requested recovery of the 2022-2025 GMP. The total planned projects were completed at 74% of the planned cost.

4.2.5 REASONS FOR DEVIATION BETWEEN ACTUAL AND PLANNED DEPLOYMENT FOR THE OVERALL PLAN

This metric is designed to measure how the Company completed its GMP.

4.2.5.1 Assumptions

The quantity and cost of devices or technology for each investment was updated from the initial GMP on a year-by-year basis. The quantity and cost of devices or technology installed in a given GMP investment year was compared on a year-by-year basis and any variations was be quantified and addressed.

4.2.5.2 Calculation Approach

The following information is reported upon per investment at the substation and circuit level where appropriate:

a. Total Number of devices or technology installed versus overall plan
b. Toal Cost of devices or technologies installed versus overall plan
c. Reason for discrepancies

4.2.6 Lessons Learned/Challenges and Successes

The Company completed the installations planned in the 2022-2025 GMP. The supply chain challenges extended lead times and delayed some projects. Where the original plan included installing VVO at seven substations, the plan was updated to install VVO on circuits at four substations through 2025. The installation efforts will continue through the ESMP.

5 EVALUATION CONSULTANT RECOMMENDATIONS

In the D.P.U. 21-80/21-81/21-82 dated October 7, 2022, the Department required the Companies to address in their Annual Reports, the status of each consultant recommendation as identified during the 2018-2021 term and that may be identified during the 2022-2025 term. (Id. 108). The following section summarizes the Guidehouse evaluation recommendations from the beginning of the grid modernization plan implementation and through the 2022-2025 plan. The recommendations have been combined by investment category. For efficiency, duplicate recommendations have only been listed one time.

Guidehouse will make recommendations for the 2025 program year in their 2025 Program Evaluation, to be submitted to the department on or before July 1, 2026. The Company plans to review and implement recommendations as appropriate. There are no plans to formally submit the Company's assessments of the recommendations to the Department as this document is the final report for the Grid Modernization Program.

5.1 ADMS RECOMMENDATIONS

5.1.1 Recommendation 1

The EDCs should plan out each investment moving forward to explicitly include capital and operational components of ADMS/ALF to insure complete visibility both internally and externally.

5.1.1.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company implemented ADMS in Term 1. The company was primarily focused on the foundational elements of ADMS (i.e. SCADA, OMS, and VVO). The Company integrated ADMS with GIS, CIS and IVR.

5.1.1.2 How was the Recommendation Considered for 2022-2025 Plan Development?

As Term 2 continues, the Company continues to look for additional ways to implement additional functionality. For instance, the Company is currently working with the ADMS manufacturer to implement of switch order management.

5.1.1.3 Implementation Status of Recommendation

The Company has accepted this recommendation and will continue to identify ways to increase the functionality of the ADMS system.

5.1.2 Recommendation 2

The EDCs should continue to keep investments in cleaning data to support ADMS/ALF separate from investments in the actual ADMS software, implementation, and operationalization in order to avoid common problems experienced in the industry.

5.1.2.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company did not propose to implement ALF as part of its plan. The Company uses internal staff to clean and update data for the ongoing operation of the ADMS system.

5.1.2.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company will continue to use internal staff to clean and update data for the ongoing operation of the ADMS system.

5.1.2.3 Implementation Status of Recommendation

The Company has accepted and implemented this recommendation and will continue to use internal staff to clean and update data for the ongoing operation of the ADMS system.

5.1.3 Recommendation 3

Continue progressing circuits into go-live status (i.e., full operation) within ADMS/ALF to confirm complete understanding of the challenges, barriers, and costs associated with fully operationalizing ADMS/ALF. Guidehouse found that as each EDC gets closer to operationalization of the ADMS/ALF, more challenges and unknowns appear. Getting visibility into these early can help ensure that EDC plans remain on track.

5.1.3.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company progresses circuits through various levels of testing prior to going live with the circuit in ADMS.

5.1.3.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company will continue to progresses circuits through various levels of testing prior to going live with the circuit in ADMS.

5.1.3.3 Implementation Status of Recommendation

The Company accepts and implemented this recommendation.

5.1.4 Recommendation 4

EDCs must internalize that ADMS will continue to be foundational for other programs and technologies (e.g., Distribution Automation, M&C, and VVO) and plan for this dependency in future technology implementation.

5.1.4.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company has made ADMS an enterprise system and includes VVO, SCADA, OMS, unbalanced load flow and other functionality yet to be deployed.

5.1.4.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company will continue to advance ADMS as and enterprise system.

5.1.4.3 Implementation Status of Recommendation

The Company accepts and implemented this recommendation.

5.1.5 Recommendation 5

As the scope of ADMS implementations increases at the EDCs, continuing to capture, clean, and mature data is of paramount importance. The level of effort required to capture, clean, and mature data can become an impediment to successful ADMS implementation and managing this proactively is critical to success.

5.1.5.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company has had GIS for many years and has a process in place for keeping the data up to date. GIS is used as the basis for the network model within ADMS. The GIS update is pushed to ADMS on a routine basis.

5.1.5.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company will continue with the process it currently has in place.

5.1.5.3 Implementation Status of Recommendation

The Company accepts and implemented this recommendation.

5.1.6 Recommendation 6

Despite Unitil's ADMS spend coming in under plans during PY 2022, spend plans for 2023 through 2025 are unchanged since submission of updated 2022 - 2025 GMP plans in response to 2021 DOER information requests. Guidehouse encourages Unitil to reassess whether additional activity, and therefore spend, not conducted in PY 2022 requires additional spend to be projected for 2023 through 2025. This is especially important, as ADMS spend and deployment are closely tied to the M&C and VVO investment areas, which faced delays in deployment in recent years.

5.1.6.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company has reassessed its spending forecast and provided its best indication of the forecasted spend.

5.1.6.2 How was the Recommendation Considered for 2022-2025 Plan Development?

This recommendation was not made prior to the plan development.

5.1.6.3 Implementation Status of Recommendation

The Company accepts and implemented this recommendation.

5.1.7 Recommendation 7

Additional control functions are planned for circuits with ADMS for all EDCs. These control functions may yield additional reliability benefits above and beyond those realized with ADA and M&C investments. If additional control functions such as FLISR are deployed on ADMS circuits in PY 2024 or PY 2025, the EDCs should consider conducting a case study of the reliability benefits of the ADMS control functions.

5.1.7.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company does not have formal plans for FLISR at this point.

5.1.7.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company does not have formal plans for FLISR at this point.

5.1.7.3 Implementation Status of Recommendation

The Company will accept this recommendation if FLISR projects are implemented.

5.1.8 Recommendation 8

Unitil is moving towards having active control of ADMS-VVO in all four planned substations. To avoid delays in implementation and the remaining planned testing, Unitil may be able to anticipate and/or do scenario planning to understand how to accommodate additional DER penetration on circuits from these substations to avoid the unbalanced load-flow challenges such as those previously encountered.

5.1.8.1 Assessment of Recommendation for 2022-2025

The Company has experienced challenges in the unbalanced load-flow due to high penetriaton of DER.

5.1.8.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company includes DER in its system planning process and will entertain generating scenario planning for unbalanced load-flow. The Company is also investigating implementing a revision to the ADMS-VVO modeling platform which will not required unbalanced load-flow, to reduce challenges from the DER penetraction.

5.1.8.3 Implementation Status of Recommendation

The Company will accept this recommendation for future consideration.

5.1.9 Recommendation 9

As ADMS capabilities continue to be refined across all EDCs, Guidehouse recommends that the EDCs provide continuous training to system planners and operators to ensure they are equipped to utilize the ADMS capabilities effectively. This will ensure that the staff is well-versed in the new system, minimizing operational risks and improving system efficiency.

5.1.9.1 Assessment of Recommendation for 2022-2025

The Engineering and Operations departments work closely with each other and communicate status of the ADMS system regularly.

5.1.9.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company agrees with this recommendation and will continue to provide training to the planners and system operators in regards to the ADMS capabilities.

5.1.9.3 Implementation Status of Recommendation

The Company has provided training to individuals working with the ADMS system and will expand that training to others as the ADMS capabilities expand.

5.2 MEASUREMENT AND CONTROL RECOMMENDATIONS

5.2.1 Recommendation 1

Guidehouse should work with the EDCs to implement an updated data collection template and format, using experience gained during the Q2'19 data collection process, to streamline data collection and make the process more efficient.

5.2.2 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company worked with Guidehouse to improve the data collection process.

5.2.2.1 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company continued to work with Guidehouse to improve the data collection process.

5.2.2.2 Implementation Status of Recommendation

The Company has accepted this recommendation and continued to work with Guidehouse to improve the data collection process.

5.2.3 Recommendation 2

EDCs should work with Guidehouse to develop a "case-study approach" to understanding reliability impacts due to M&C investments, and help distinguish between how impacts are attributed to M&C vs ADA where these investments are deployed on same circuit.

5.2.3.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company has worked with Guidehouse to develop a "case study approach". This can be difficult when there are no events that occur.

5.2.3.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company continued to work with Guidehouse to develop a "case study approach" in Term 2. This can be difficult when there are no events that occur.

5.2.3.3 Implementation Status of Recommendation

The Company has accepted this recommendation and will continue working with Guidehouse on a "case study approach".

5.2.4 Recommendation 3

In the future, the EDCs could consider a more sophisticated statistical approach to assessing the reliability impacts of M&C investments. Such techniques require more outage data collection (e.g., outage cause), feeder characteristics (e.g., length, customers, location), equipment installed (e.g., number and type of reclosers), knowledge of other activities (e.g. timing of vegetation trimming), integration with weather data (e.g., hourly wind speed and direction) for feeders that receive the M&C investment and those that do not, but promise more insight on whether the M&C investments are yielding reliability improvements in MED and non-MED situations. This type of approach is more complex and requires additional data collection and more analysis, but it could control for weather and other factors effecting reliability.

5.2.4.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company collects the outage data defined above, but has not developed a means to efficiently compare circuits with and without M&C investments.

5.2.4.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company did not include a means to efficiently compare circuits with and without M&C investments in its 2022-2025 GMP.

5.2.4.3 Implementation Status of Recommendation

The Company has not accepted this recommendation at this time. The Company has not developed a means to efficiently and accurately compare circuits with and without M&C investments.

5.2.5 Recommendation 4

The CKAIDI and CKAIFI reliability related Performance Metrics as defined 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 storm activity between years can cause significant changes in these metrics, as apparently happened in PY2020.

- Continue to track these Performance Metrics, but to establish other methods of isolating the specific impacts of Grid Modernization investments

- Additional Performance Metrics should be explored to determine if it is possible to capture the actual reliability performance attributable to the investments. Exploration could include:
  - Reviewing the data and techniques necessary to understand the relationship between circuit reliability and weather conditions, vegetation management cycles and other reliability drivers that are independent of the grid modernization investments.
  - Expanding the use of case studies to cover a greater proportion of the investments—more outage cases examined on more circuits
  - Leveraging new processes and collecting data to more efficiently perform outage case studies, and perhaps extrapolate these results to a broader set of circuits to understand investment performance with more certainty
  - Comparing number of customers out and customer minutes of interruption (CMI) that occurred, with the number of customers out and CMI that would have occurred without Grid Modernization investments."

5.2.5.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company has not conducted this analysis outside of case study analysis.

5.2.5.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company is willing to work with the EDCs and Guidehouse to develop this type of analysis.

5.2.5.3 Implementation Status of Recommendation

The Company has not accepted this recommendation but is willing to work with the EDCs and Guidehouse to develop this type of analysis.

5.2.6 Recommendation 5

The use of currently defined CKAIDI and CKAIFI reliability related Performance Metrics—which are circuit level metrics—has increasing challenges over time as circuits get re-configured or retired and new circuits are constructed. The comparability of each circuit in the program year to its baseline depends on that circuit not having been reconfigured or significantly changed (e.g., a normally open switch between circuit segments is changed to operate as normally closed, changing the customer counts and outage measurements on that circuit). The number of circuits that are comparable between baseline and program year is reduced year after year as more circuits change due to ongoing operation of the system.

- Explore metrics that are robust to these operating changes to help ensure that Grid Mod investment assessment based on these metrics are not misleading, and that they are able to better capture the impact of the investment.

5.2.6.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company has not yet implemented additional reliability analysis that can accurately measure the impact of GMP investments.

5.2.6.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company is willing to work with the EDCs and Guidehouse to develop this type of analysis.

5.2.6.3 Implementation Status of Recommendation

The Company does not accept this recommendation but is willing to work with the EDCs and Guidehouse to develop this type of analysis.

5.2.7 Recommendation 6

Current metrics do not provide an understanding of how M&C and ADA investments facilitate easier interconnection, or more capacity, of DER added to the system

- Consider developing additional metrics and/or performing pilot projects that utilize the installation of ADA and M&C investments at DER locations to understand the value or benefits that are provided. This would provide actual data on the effectiveness of these investments to support DER integration.

5.2.7.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company does not have and has not proposed M&C investments at DER locations.

5.2.7.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company has not proposed M&C investments at DER locations.

5.2.7.3 Implementation Status of Recommendation

The Company did not accept this recommendation.

5.2.8 Recommendation 7

Case studies show detailed functioning and impact of GMP devices, and they are proving to be a useful tool in understanding the effectiveness of the Grid Modernization investments. Based on case studies performed, the M&C investment is yielding reliability and service delivery benefits to customers for each of the EDCs.

- Continue to perform case studies in future evaluations, and increase the use of case studies where practicable, to analyze the mitigation of customer outages and help determine the effectiveness of Grid Modernization investments in improving reliability and service delivery
- Continue the deployment of M&C technologies as part of the Grid Modernization Program and continue to monitor progress (including through amended or additional metrics to be determined by the Department).

5.2.8.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company has worked and continued to work with Guidehouse on identifying case studies.

5.2.8.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company continued to work with Guidehouse on identifying case studies.

5.2.8.3 Implementation Status of Recommendation

The Company accepted and implemented this recommendation.

5.2.9 Recommendation 8

The CKAIDI and CKAIFI reliability related Performance Metrics as defined 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 storm activity between years can cause significant changes in these metrics, as apparently happened in PY2020 and PY2021. This observation has been made previously, and these recommendations were made last year, but bear repeating.

- Continue to track these Performance Metrics, but establish other methods of isolating the specific impacts of Grid Modernization investments.
- Additional Performance Metrics should be explored to determine if it is possible to capture the actual reliability performance attributable to the investments. Exploration could include:
  - Exploring the pros and cons of making the reliability metrics baseline a rolling average of, perhaps, the most recent 3 years, as opposed to the fixed years of 2015 through 2017. The fixed baseline has the issue, as pointed out in the report, that individual circuits are reconfigured over time, go out of service, and new circuits are created, making circuit-wise comparisons over time more challenging.
  - Exploring the pros and cons of understanding the timing and sequencing of reliability events more closely in the first several minutes of the event. This timing would lend insight whether an event was resolved within a 1 minute versus a 5 minute threshold, which would impact CKAIFI metrics. As the network becomes more complex (e.g., increased DER penetration, additional switching to reconfigure for changing loads), the processing logic to perform proper load and device status before automation controls are used will become more complex and tend to take longer. So, understanding these dynamics will grow in importance.
  - Reviewing the data and techniques necessary to understand the relationship between circuit reliability and weather conditions, vegetation management cycles and other reliability drivers that are independent of the grid modernization investments
  - Expanding the use of case studies to cover a greater proportion of the investments—more outage cases examined on more circuits
  - Leveraging new processes and data collection to perform outage case studies more efficiently, and perhaps extrapolate these results to a broader set of circuits to understand investment performance with more certainty
  - Comparing number of customers out and customer minutes of interruption (CMI) that occurred, with the number of customers out and CMI that would have occurred without Grid Modernization investments.

- Developing a way to expand the use of counter-factual analysis on a broader basis than what is currently being done in the Case Studies could help develop a better understanding of overall system impacts from the ADA investments.

5.2.9.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company has not conducted this analysis outside of case study analysis.

5.2.9.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company is willing to work with the EDCs and Guidehouse to develop this type of analysis.

5.2.9.3 Implementation Status of Recommendation

The Company has not accepted this recommendation but is willing to work with the EDCs and Guidehouse to develop this type of analysis.

5.2.10 Recommendation 9

On non-EME days, Eversource circuits with M&C investment showed lower (improved from baseline) average outage duration, whereas National Grid and Unitil circuits with M&C showed slightly higher (worse) average outage duration. Including EME days, Eversource, National Grid and Unitil performed better than baseline.

Recommendation: continue tracking and monitoring this investment area to try to verify the impacts (noting that the defined metric does not paint a complete picture as has been previously observed) on circuits receiving Term 2 investments as well as those that have received Term 1 investment (to understand the longer term impacts of the investments over time). Case studies (discussed below) can provide additional insight.

5.2.10.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company is willing to work with the EDCs and Guidehouse to continue to evaluate data.

5.2.10.2 How was the Recommendation Considered for 2022-2025 Plan Development?

This recommendation was not made prior to the plan development.

5.2.10.3 Implementation Status of Recommendation

The Company is willing to work with the EDCs and Guidehouse to continue to evaluate data.

5.2.11 Recommendation 10

Based on case studies performed, the M&C investment is yielding reliability and service delivery benefits to customers of each of the EDCs.

Recommendation: continue to explore case studies for Term 1 investments to validate operation. Also, consider case studies for Term 2 investments to validate and verify their operation.

5.2.11.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company is willing to work with the EDCs and Guidehouse to continue to evaluate case studies.

5.2.11.2 How was the Recommendation Considered for 2022-2025 Plan Development?

This recommendation was not made prior to the plan development.

5.2.11.3 Implementation Status of Recommendation

The Company is willing to work with the EDCs and Guidehouse to continue to evaluate case studies.

5.2.12 Recommendation 11

Since Unitil's M&C investments are focused on the substation, circuit power restoration work is still predominantly manual, as evident in the two Unitil case studies.

Recommendation for Unitil: evaluate the benefits and costs of M&C and automation investments outside the substation.

5.2.12.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company has not proposed M&C investments outside of the substation in Term 1 or Term 2.

5.2.12.2 How was the Recommendation Considered for 2022-2025 Plan Development?

This recommendation was not made prior to the plan development.

5.2.12.3 Implementation Status of Recommendation

The Company has not proposed M&C investments outside of the substation in Term 2.

5.2.13 Recommendation 12

The CKAIDI and CKAIFI reliability related Performance Metrics as defined have deficiencies in measuring the effectiveness of Grid Modernization Investments. These items have been pointed out as recommendations in Evaluation Reports from prior program years, and so the details are not repeated here. The case study approach addresses some of these shortcomings.

Recommendation: Continue to track these Performance Metrics, but continue to perform case studies (for Term 1 and Term 2 investments as appropriate, as mentioned above) and explore other methods of isolating the specific impacts of Grid Modernization investments (e.g., frequency of successful device operation).

5.2.13.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company is willing to work with the EDCs and Guidehouse to continue to evaluate case studies.

5.2.13.2 How was the Recommendation Considered for 2022-2025 Plan Development?

This recommendation was not made prior to the plan development.

5.2.13.3 Implementation Status of Recommendation

The Company is willing to work with the EDCs and Guidehouse to continue to evaluate case studies.

5.2.14 Recommendation 13

Key Findings:
Unitil was unable to find SCADA readings to verify whether operators had issued SCADA commands to remotely control (open/close) the substation circuit breakers. Therefore, remote control via SCADA could not be determined.

Recommendation: Guidehouse recommends Unitil investigate whether the major event on 3/14/23 presented an opportunity for using SCADA control and take steps to utilize SCADA control capability in future substation events.

5.2.14.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company is willing to work with the EDCs and Guidehouse on this evaluation.

5.2.14.2 How was the Recommendation Considered for 2022-2025 Plan Development?

This recommendation was not made prior to the plan development.

5.2.14.3 Implementation Status of Recommendation

The Company is willing to work with the EDCs and Guidehouse on this evaluation.

5.2.15 Recommendation 14

Guidehouse recommends that Unitil continue training programs for the new ADMS SCADA system and conduct exercises to ensure operators feel comfortable working quickly and efficiently in the new environment as they have been in working in the legacy SCADA environment.Assessment of Recommendation for 2018-2021 and 2022-2025

The Company is willing to work with the EDCs and Guidehouse on this evaluation.

5.2.15.1 How was the Recommendation Considered for 2022-2025 Plan Development?

This recommendation was not made prior to the plan development.

5.2.15.2 Implementation Status of Recommendation

The Company accepts this recommendation and continues to train the users of the ADMS system.

5.3 VVO RECOMMENDATIONS

5.3.1 Recommendation 1

To provide results for reporting of performance metrics in 2021, continue with rapid pace of VVO device deployment in early 2020 to ensure adequate data (specifically VVO On / Off data) are collected for the analysis.

5.3.1.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company did not meet this recommendation as VVO was not enabled until late 2022/early 2023.

5.3.1.2 How was the Recommendation Considered for 2022-2025 Plan Development?

This was a recommendation for 2020 and was not focused on future years.

5.3.1.3 Implementation Status of Recommendation

The Company did not accept this recommendation as it was not able to complete this deployment.

5.3.2 Recommendation 2

Where possible, conduct VVO device deployment and VVO IT system commissioning in tandem to reduce the amount of time needed for post-deployment VVO commissioning

5.3.2.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company was not successful implementing VVO in Term 1. The Company plans to take this approach in Term 2.

5.3.2.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company plans to continue with this approach.

5.3.2.3 Implementation Status of Recommendation

The Company accepts and implemented this recommendation.

5.3.3 Recommendation 3

Each EDC should discuss the role of load balancing, phase balancing in the deployment of VVO, and why neither were chosen to be conducted.

5.3.3.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company conducts phase balancing and load balancing as part of annual distribution planning and outside of the GMP.

5.3.3.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company conducts phase balancing and load balancing as part of annual distribution planning and outside of the GMP.

5.3.3.3 Implementation Status of Recommendation

The Company believes this is a good approach, but does not implement it as part of the GMP.

5.3.4 Recommendation 4

Once VVO is ready for On / Off testing, EDCs follow VVO On / Off cycling for at least 9 months, covering one full summer, one full winter, and one of either the spring or fall shoulder seasons.

5.3.4.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The company did not enable VVO on any circuits in Term 1. The Company plans on implementing this for VVO projects in Term 2.

5.3.4.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company plans on implementing this for VVO projects in Term 2.

5.3.4.3 Implementation Status of Recommendation

The Company accepted this recommendation and implemented for Term 2.

5.3.5 Recommendation 5

EDCs should continue tracking complaints along feeders receiving VVO investment to ensure the analysis of voltage-related complaints is feasible in 2021.

5.3.5.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company did not enable VVO on any circuits in Term 1. The Company plans on implementing this for VVO projects in Term 2.

5.3.5.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company tracks all voltage complaints and will be able to identify VVO related voltage complaints.

5.3.5.3 Implementation Status of Recommendation

The Company accepted this recommendation and tracks all voltage complaints and will be able to identify VVO related voltage complaints.

5.3.6 Recommendation 6

EDCs should continue discussions with Guidehouse throughout 2020, as analysis of performance metrics will begin to be fine-tuned around nuances surrounding each of the VVO feeders, including:

- Construction of baselines for analysis of performance metrics
- Distributed generation penetration, and effects of feeders with high penetration rates on analysis of performance metrics
- Customer counts per feeder, especially where some feeders have <10 customers

5.3.6.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company worked with Guidehouse to implement VVO M&V.

5.3.6.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company continued to work with Guidehouse to fine tune VVO M&V.

5.3.6.3 Implementation Status of Recommendation

The Company accepted this recommendation and continued to work with Guidehouse to fine tune VVO M&V.

5.3.7 Recommendation 7

EDCs explore voltage setpoints to determine whether further voltage reductions can be achieved when VVO is engaged.

5.3.7.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company did not enable VVO in Term 1. The Company will continue to fine tune its voltage setpoints to maximize the benefits of VVO.

5.3.7.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company will continue to fine tune its voltage setpoints to maximize the benefits of VVO.

5.3.7.3 Implementation Status of Recommendation

The Company accepted this recommendation and implemented in Term 2.

5.3.8 Recommendation 8

EDCs identify whether there is an impact of reverse power flow from distributed generation on VVO operation. The impact of reverse power flow on VVO operation may have a large impact on the evaluated performance of VVO for the upcoming spring and summer 2021 M&V periods.

5.3.8.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company did not enable VVO in Term 1.

5.3.8.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company has not identified this as a concern during testing in Term 2.

5.3.8.3 Implementation Status of Recommendation

The Company accepted this recommendation and implemented in Term 2.

5.3.9 Recommendation 9

Guidehouse and the EDCs agreed to the plan for VVO On/Off testing to continue for at least 9 months, covering summer (June, July, and August), winter (December, January, and February), and one of the spring (March, April, and May) or fall (September, October, November) shoulder seasons. To provide results for reporting of Performance Metrics later in 2021 and 2022, the EDCs should continue with this plan.

5.3.9.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The company did not enable VVO on any circuits in Term 1. The Company plans on implementing this for VVO projects in Term 2.

5.3.9.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company plans on implementing this for VVO projects in Term 2.

5.3.9.3 Implementation Status of Recommendation

The Company accepted this recommendation and implemented for Term 2.

5.3.10 Recommendation 10

EDCs should identify and take additional steps to balance load across feeders and phases before the deployment of VVO. This step can yield energy savings that could be attributed to VVO investment.

5.3.10.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company conducts phase balancing and load balancing as part of annual distribution planning and outside of the GMP.

5.3.10.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company conducts phase balancing and load balancing as part of annual distribution planning and outside of the GMP.

5.3.10.3 Implementation Status of Recommendation

The Company believes this is a good approach, but does not implement it as part of the GMP.

5.3.11 Recommendation 11

EDCs and Guidehouse should work to update stamped-approved performance metrics after completing analysis of all VVO performance metrics, based upon methods included in this evaluation report.

5.3.11.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The EDCs have proposed updates to the performance metrics in the 2022-2025 GMP.

5.3.11.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The EDCs have proposed updates to the performance metrics in the 2022-2025 GMP.

5.3.11.3 Implementation Status of Recommendation

The Company accepted and implemented this recommendation.

5.3.12 Recommendation 12

Continue to monitor performance of the VVO scheme after M&V has been completed, such as ensuring capacitor banks and pole-top regulators are responding as anticipated to VVO/ADMS commands. The EDC's performance metric estimates are reflective of the VVO scheme as it was in PY 2023. Continuously monitoring the VVO scheme to ensure all line devices are responding as anticipated will be important in ensuring evaluated performance is maintained.

5.3.12.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company continues to review daily logs to determine the performance of the VVO system and its field devices.

5.3.12.2 How was the Recommendation Considered for 2022-2025 Plan Development?

This recommendation was not made prior to the plan development.

5.3.12.3 Implementation Status of Recommendation

The Company continues to review daily logs to determine the performance of the VVO system and its field devices.

5.3.13 Recommendation 13

Provide SCADA data for one or two "placebo" circuits (i.e., circuits without VVO schemes) for the PY 2024 and PY 2025 evaluations. Using data provided for two "placebo" circuits within the PY 2023 evaluation, Guidehouse identified that the EDC's On/Off testing data was biased by extended pauses to the On/Off testing conducted. In some cases, this led to an oversampling of hotter days when VVO was engaged relative to when VVO was disengaged, and in others this led to an oversampling of cooler days when VVO was engaged relative to when VVO was disengaged. This poses a threat to the RCT program design of On/Off testing and required the data to be rebalanced via a matching algorithm summarized in Section 2.1.3. Providing SCADA for "placebo" circuits will allow Guidehouse to assess whether testing data for the VVO circuits needs to be rebalanced.

5.3.13.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company worked with Guidehouse on this recommendation.

5.3.13.2 How was the Recommendation Considered for 2022-2025 Plan Development?

This recommendation was not made prior to the plan development.

5.3.13.3 Implementation Status of Recommendation

The Company worked with Guidehouse on this recommendation and provided data as requested.

5.3.14 Recommendation 14

Increase the cadence of VVO On/Off testing. Guidehouse recommends shifting from week on / week off testing to either testing daily (i.e., day on / day off), every other day, every two days, every three days, or every four days (i.e., four days on / four days off). Increasing the cadence of testing will improve the likelihood of balance in temperatures, day types, and other factors that influence grid conditions. This ultimately allows for the RCT design of VVO On/Off testing to yield unbiased Performance Metric estimates.

5.3.14.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company is evaluating the ability to practically implement this recommendation.

5.3.14.2 How was the Recommendation Considered for 2022-2025 Plan Development?

This recommendation was not made prior to the plan development.

5.3.14.3 Implementation Status of Recommendation

The Company accepted the recommendation and implemented a 4 day On/Off testing frequency for the evaluation testing performed in 2024.

5.3.15 Recommendation 15

Once a schedule with increased cadence has been determined for VVO On/Off testing, the EDCs should make every effort to comply with the pre-determined schedule. If compliance is achieved, there should be a balance of temperatures and other conditions correlated with system demand, voltage, and power factor, thereby leading to VVO impact estimates that are unbiased. Failure to comply, such as pausing On/Off testing and leaving VVO in its engaged or disengaged state for an extended period of time, will increase the likelihood of an invalid RCT in the PY 2024 and PY 2025 evaluations. If an invalid RCT is identified, Guidehouse will need to rebalance the data using the approach outlined in Section 2 to reduce the risk of biased VVO impact estimates.

5.3.15.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company accepted this recommendation and strives to meet the on/off schedule.

5.3.15.2 How was the Recommendation Considered for 2022-2025 Plan Development?

This recommendation was not made prior to the plan development.

5.3.15.3 Implementation Status of Recommendation

The Company accepted this recommendation and has successfully implemented a 4 day On/Off frequency for multiple substations in 2024.

5.3.16 Recommendation 16

To identify causes of lower performance during peak demand hours, Unitil may consider investigating data collected at pole-top regulators and capacitor banks to determine whether there are differences in how voltage is lowered and flattened during peak hours (4:00 p.m. to 10:00 p.m., non-holiday weekdays between May 1 and September 30) relative to all other hours of the day. It may be the case that Townsend circuits' line devices were not responding as expected to VVO signals during the identified peak period..

5.3.16.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company accepted this recommendation and is currently working with Guidehouse on data review.

5.3.16.2 How was the Recommendation Considered for 2022-2025 Plan Development?

This recommendation was not made prior to the plan development.

5.3.16.3 Implementation Status of Recommendation

The Company accepted this recommendation and worked with Guidehouse on data review.

5.4 COMMUNICATIONS RECOMMENDATIONS

5.4.1 Recommendation 1

Unitil should conduct in-house laboratory testing of all equipment proposed to be connected to the AT&T FirstNet. Laboratory testing of equipment before field deployment is good practice to reduce the potential of rework.

5.4.1.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company completed laboratory testing prior to sending communications equipment out into the field.

5.4.1.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company will continue to conduct laboratory testing prior to sending communications equipment out into the field.

5.4.1.3 Implementation Status of Recommendation

The Company accepted and implemented this recommendation.

5.4.2 Recommendation 2

Unitil has decided to install field radios in conjunction with VVO rollout to improve efficiency of radio deployment. While Guidehouse agrees with this approach, the risk could be a delay in VVO investment deployment if unforeseen communications issues arise.

- At the locations where VVO equipment will be installed, field signal strength measurements should be taken to validate that the public network will provide acceptable communications performance

5.4.2.1 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company completes testing of all VVO sites to ensure the modems can communicate with the communications network.

5.4.2.2 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company will continue the process of testing VVO sites to ensure the modems can communicate with the communications network.

5.4.2.3 Implementation Status of Recommendation

The Company accepted and implemented this recommendation.

5.4.3 Recommendation 1

Guidehouse should work with the EDCs to implement an updated data collection template and format, using experience gained during the Q2'19 data collection process, to streamline data collection and make the process more efficient.

5.4.4 Assessment of Recommendation for 2018-2021 and 2022-2025

The Company worked with Guidehouse to improve the data collection process.

5.4.4.1 How was the Recommendation Considered for 2022-2025 Plan Development?

The Company continued to work with Guidehouse to improve the data collection process.

5.4.4.2 Implementation Status of Recommendation

The Company has accepted this recommendation and continued to work with Guidehouse to improve the data collection process.

6 COMPANY-SPECIFIC REPORTING – CUSTOMER-FACING INVESTMENTS

6.1 AMI

The Company filed its 2022-2025 Grid Modernization Plan on July 1, 2021. In this filing, the Company was required to file an AMI plan. The Company's plan consisted of a meter replacement to transition from TS2 to Gridstream PLX technology.

On June 29, 2022, the Company was notified Landis+Gyr would discontinue their Gridstream PLX technology. Landis+Gyr referenced supply chain challenges and the risk of obsolescing components that support PLC communications as the reasons for discontinuing this product. Landis+Gyr are recommending a new communications technology using a combination of radio frequency and/or cellular. The Landis+Gyr transition plan identifies June 2023 as the end-of-purchase for PLX endpoints and support for the powerline carrier system would continue until 2029.

The Company held several meetings with Landis+Gyr from July – November determine if there was a way to simply replace the communications technology (i.e. replace powerline carrier with RF mesh technology). It became apparent that this approach is not available and the Company would be required to replace all meters as well as the communications technology prior to 2029.

At that point, the Company decided to go through a competitive bidding process for a new AMI system. The RFP was issued on December 22, 2022 with responses due March 1, 2023. The Company spent several months during 2023 evaluating vendor proposals and ultimately selected Landis+Gyr as the vendor for the replacement AMI system which consists of a new RF based field area network, a cloud-based software head-end system, and the replacement of all existing PLC electric meters.

The Company identified this information as a variation from the previously approved AMI project in the 2022-2025 plan. As such, The Company filed a petition with the Department (D.P.U. 24-54) to revise the scope of the original AMI project and obtain preauthorization of these AMI investments. On March 28, 2025 the Department approved this petition. The capital investments and O&M costs presented in this report represent the revised AMI project scope.

6.1.1 Description of Work Completed

In 2025, the Company completed the installation of the AMI software Head-End System (HES) and the installation of the field area network (FAN) and the replacement of all electric meters.

6.1.2 Lessons Learned/Challenges and Successes

The Company had anticipated that its existing AMI system would be available to support its Grid Modernization efforts. The unforeseen circumstances of this system being phased out by the vendor presented the Company with both challenges and opportunities. The new system provides the opportunity to enhance operational grid visibility and improve modeling accuracy by enabling real time metering data to be integrated with ADMS functionality.

6.1.3 Actual versus Planned Implementation and Spending

The table below represents the actual versus planned spending of the AMI project.

	2022		2023		2024		2025	
Year	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
Capital Costs	$2,346,000	$76,270	$0	$0	$4,580,922	$3,865,522	$7,136,120	$5,923,510
O&M Costs	$0	$0	$0	$0	$0	$0	$132,081	$0
Total Costs	$2,346,000	$76,270	$0	$0	$4,580,922	$3,865,522	$7,268,201	$5,923,041

Table 21 – AMI 2022-2025 Actual versus Forecast Spending

6.1.4 Performance on Implementation/Deployment

The Company completed the installation of the AMI system including the replacement of all electric meters in 2025.

6.1.5 Description of Benefits realized as the Result of Implementation

The new AMI system is providing 15 minute interval usage data and 5 minute interval voltage data at all electric meters. The new AMI system is also providing near real-time outage and restoration notifications to our test OMS system. The Company is currently evaluating the reliability of these notifications and is intending to integrate these in our production OMS later this year.

6.2 CUSTOMER ENGAGEMENT AND EXPERIENCE

The Company‘s approach to digital customer engagement has shifted in accordance with evolving customer needs and industry trends. The Company maintains it's core digital engagement and experience objective, which is to promote personalized and interactive experiences that guide and empower users to make informed decisions to best manage their energy use. Leveraging and enhancing established tools continues to promote cost efficiencies and the ability to agilely respond to evolving industry trends, regulatory requirements, and real-time customer feedback.

6.2.1 Description of Work Completed

Work completed in 2025:

- Customer Experience Management Solution: The Company contracted with Systems & Software (existing CIS vendor) and launched the system in April of 2024. In early 2025, several system enhancements were executed, including enhanced outage alert functionality designed to proactively alert customers of an outage affecting their service location and to provide real-time outage status updates. As electric customer meters are upgraded to Revelo AMI meters, the Company has worked to ensure customer access to register read data through their online accounts. Accessibility, digital payment, and security enhancements were also executed on the company portal in 2025. In addition, the Company initiated an effort to consolidate energy saving and conservation resources on their company website and developed tools to assist customers in navigating these options. The Company refers to these resources and tools as our Energy Navigator platform, which was launched in early 2026.

6.2.2 Lessons Learned/Challenges and Successes

The Company continues to seek opportunities to promote tools and programs designed to help customers manage energy use and costs, and to streamline the customer journey for enrollment and use of energy conservation offerings at minimal costs. To date, this has been accomplished through the enhancement of existing digital customer engagement products. The Company continues to seek worthwhile software investments to promote customer education, engagement and satisfaction, such as behind the meter (BTM) and disaggregation tools. Through the aggregation of existing web content and internal development of interactive web tools that generate personalized energy conservation recommendations to customers, the Company is prepared to gain customer insight on opportunities to further enhance the digital experience through the implementation of additional software investments.

6.2.3 Actual Versus Planned Implementation and Spending

The following table represents historic actual versus planned costs to implement the functionality associated with the Customer Engagement and Experience project. Costs associated with project work from 2024 and beyond have and will be shared with other Unitil Corporation subsidiaries.

Description	2022		2023		2024		2025	2026 - 2030
	Plan	Actual	Plan	Actual	Plan	Actual	Actual	Plan
Customer Experience Mapping/Implementation	$186,000	$16,922	$75,000	$0	$0	$0	$0	$0
Customer Engagement Platform					$0	$0	$0	$0
Utility Bill Redesign	$55,000	$14,316	$16,000	$9,120				
Customer Engagement and Experience Total	$241,000	$31,238	$91,000	$9,120	$0	$0	$0	$0

Table 22 - Customer Engagement and Experience Project Plan

The following table provides a historic summary of actual versus planned spending allocation of the overall project. Capital costs associated with project work from 2024 and beyond have and will be funded by other Unitil Corporation subsidiaries. The planned O&M Costs are vendor-charged subscription fees used to host and maintain the cloud-based solutions provided to the customers.

Year	2022		2023		2024		2025	
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
Capital Costs	$241,000	$31,238	$91,000	$9,120	$0	$0	$0	$0
O&M Costs	$0	$16,151	$16,151	$16,151	$16,151	$16,420	$16,151	$17,241
Total Costs	$241,000	$47,389	$107,151	$25,271	$16,151	$16,420	$16,151	$17,241

Table 23 - Customer Engagement and Experience 2022-2025 Actual Spending

6.2.4 Performance on Implementation/Deployment

The Company completed the Customer Experience Management Solution portion of the project in 2024 in addition to planned system enhancement work from 2025 to date. All projects have met expected outcomes.

6.2.5 Description of Benefits realized as the Result of Implementation

Customer satisfaction remained high at 87% in 2025. The Company is currently ranked in the 2nd quartile based on satisfaction ratings nationally.

6.2.6 Key Milestones

Key Milestones Completed for the Customer Experience Initiatives:

- Apogee Rate Comparison Tool: April, 2023
- Utility Bill Redesign: April, 2023
- Customer Experience Management Solution: April, 2024
- Customer Experience Management Solution Enhancements: 2025-2026
- Energy Navigator: March, 2026

6.3 DATA SHARING PLATFORM

In March of 2022, in response to NH PUC filed order number 26,589 approving a settlement agreement setting the stage for the completion of the design and build out of the framework required to support a state-wide Multi-Use Energy Data Platform, Unitil Corporation subsidiary, Unitil Energy Systems (UES) located in New Hampshire ("NH") filed a proposed approach for data sharing in NH PUC Docket No. DE 19-197. Effective June 21, 2026, the New Hampshire statute directing the establishment and operation of a statewide online energy data platform was repealed. As a result, the project is not moving forward at this time.

In November of 2022, the MA D.P.U. issued a Final Order on the second grid modernization plans filed by the EDCs directing the EDCs to convene a statewide stakeholder working group to address topics related to AMI implementation plans. In March of 2025, the MA D.P.U. filed a procedural memorandum requesting input on third-party access to customer AMI usage data and customer usage data sharing. In February of 2026, the EDCs submitted, for Department approval, an AMI data access plan similar to the state-wide Multi-Use Energy Data Platform proposed in NH. The goal of this proposed centralized AMI data repository plan is to allow customer and third parties near-real time access to AMI data.

6.3.1 Description of Work Completed

In April of 2024, Unitil completed a major planned upgrade of its Customer Information System and Customer Engagement Portal. The completion of this upgrade has enabled the Company to move forward with plans to introduce Green Button Connect My Data functionality by the end of the 2026 calendar year. This industry standard technology will form the backbone for Unitil's data sharing strategy.

6.3.2 Lessons Learned/Challenges and Successes

The Company experienced challenges associated with the process of mining and combining customer energy and billing data from individual, disparate systems to the platform to support a proposed "Logical Data Model" in New Hampshire, leading to schedule impacts. Numerous technical and non-technical hurdles exist with retrieving and processing the data necessary to support the platform. The Company has proposed a similar Logical Data Model in MA, which will require additional mapping of data fields unique to MA. To address schedule impacts resulting from these complexities, the Company has engaged a number of internal and external stakeholders to inform data validation, usability, quality assurance, and testing strategy.

6.3.3 Lessons Learned/Challenges and Successes

The Company experienced challenges associated with the process of mining and combining customer energy and billing data from individual, disparate systems to the platform to support a proposed "Logical Data Model" in New Hampshire, leading to schedule impacts. Numerous technical and non-technical hurdles exist with retrieving and processing the data necessary to support the platform. The Company has proposed a similar Logical Data Model in MA, which will require additional mapping of data fields unique to MA. To address schedule impacts resulting from these complexities, the Company has engaged a number of internal and external stakeholders to inform data validation, usability, quality assurance, and testing strategy.

6.3.4 Actual versus Planned Implementation and Spending

The following table represents historic actual versus planned costs to implement the functionality associated with the Data Sharing project. Costs associated with project work from 2024 and beyond have and will be funded by other Unitil Corporation subsidiaries.

Year	2022 Plan	2022 Actual	2023 Plan	2023 Actual	2024 Plan	2024 Actual	2025 Plan	2025 Actual
Capital Costs	$466,000	$0	$0	$0	$466,000	$0	$0	$0
O&M Costs	$ 0	$0	$0	$0	$0	$0	$0	$0
Total Costs	$466,000	$0	$0	$0	$466,000	$0	$0	$0

Table 24 - Data Sharing 2022-2025 Actual Spending

6.3.5 Performance on Implementation/Deployment

This project began in 2024. Further development and testing of the platform are scheduled to occur thorough 2026. The Company anticipates to deploy the platform by the end of the 2026 calendar year.

6.3.6 Description of Benefits realized as the Result of Implementation

This project seeks to enable expanded uses for energy usage data designed for a number of user types. The Company anticipates that the automating the transfer of energy data via Green Button Connect My Data may likely result in increased use of customer data to inform efforts related to the following:

- Energy consumption management
- Energy conservation
- Energy costs management
- Exploration of new products and services offered
- Transmission capacity costs management
- Deferred spending on capacity improvements
- Community aggregations
- Broaden DER provider consumer access

6.3.7 Key Milestones

The Company looks forward to continued collaboration in executing milestones associated with the proposed centralized AMI data repository plan in Massachusetts. Green Button Connect My Data capabilities will serve as the foundational technical building blocks to inform data sharing efforts within all Unitil subsidiaries.

7 CONCLUSION

In 2021, the Company submitted a 2022-2025 Grid Modernization Plan, which included planned implemation in several categories of modernization. The plan was slightly revised as detailed design was complete and as issues were encountered with implementation. This report compares the implementation and actual costs to the revised 2022-2025 plan. As displayed above, except for one project, the Company was successful in implementin the plan as revised. The project to implement a damage assessment, Mobile Information Management System (MIMS), application under the Workforce Management category, was not fully commissioned by the end of 2025, and therefore is not being included in the request for recovery of the Grid Modernzation Factor. However, the Company is continuing to move forward with the project, to gain the benefits to Unitil customers, expected fromt the application. The VVO project was revised to defer that installation of devices at three substations due to material lead time. The Company successfully completed the commissing 100 % of the VVO equipment per the revised plan. The AMI integration project was revised to replace the full AMI communication network and all customer meters, as petitioned with the Department (D.P.U. 24-54), and approved by the Department in order D.P.U.24-54-A. The Company was successful in replacing the full AMI system per the revised plan within the GMP 2022-2025 time frame.

Appendix 1

D.P.U. Appendix 1 Template

NOTE:

D.P.U. APPENDIX 1 TEMPLATE PROVIDED IN EXCEL FORMAT

Appendix 2

System Automation Saturation

2025 EOY

			Partially Automated Devices						Fully Automated Devices					
Substation	**Circuit**	**Customers**	**Feeder Breakers** [Note 1]	**Distribution Reclosers, etc.** [Note 2]	**Padmount Switchgear**	**Network Transformers/ Protectors**	**Capacitors & Regulators** [Note 3]	**Partially Automated Device Sub-Totals**	**Feeder Breakers** [Note 1]	**Distribution Reclosers, etc.** [Note 2]	**Padmount Switchgear**	**Network Transformers/ Protectors**	**Fully Automated Device Sub-Totals**	**System Automation Saturation**
Beech Street	1W1	618	0	0	0	0	0	0	1	0	0	0	1	618.0
Beech Street	1W2	2,024	0	0	0	0	0	0	1	1	0	0	2	1,012.0
Beech Street	1W4	1,693	0	1	0	0	0	1	1	0	0	0	1	1,128.7
Beech Street	1W6	1	0	0	0	0	0	0	1	0	0	0	1	1.0
Beech Street		**4,336**	**0**	**1**	**0**	**0**	**0**	**1**	**4**	**1**	**0**	**0**	**5**	788.4
Canton Street	11H10	removed from service												---
Canton Street	11H11	removed from service												---
Canton Street	11W11	1,794	0	0	0	0	0	0	1	0	0	0	1	1,794.0
Canton Street	11W12	1,512	0	0	0	0	0	0	1	0.5	0	0	1.5	1,008.0
Canton Street		**3,306**	**0**	**0**	**0**	**0**	**0**	**0**	**2**	**0.5**	**0**	**0**	**2.5**	1,322.4
Townsend	15W14	1	0	0	0	0	0	0	1	1	0	0	2	0.5
Townsend	15W15	1	0	0	0	0	0	0	1	0	0	0	1	1.0
Townsend	15W16	1,542	0	0	0	0	9	9	1	0	0	0	1	280.4
Townsend	15W17	575	0	0	0	0	1	1	1	0	0	0	1	383.3
Townsend		**2,119**	**0**	**0**	**0**	**0**	**10**	**10**	**4**	**1**	**0**	**0**	**5**	211.9
Nockege	20W22	914	0	0	0	0	0	0	1	0	0	0	1	914.0
Nockege		**914**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**0**	**1**	914.0
Wallace Road	1341	0	0	0	0	0	0	0	2	0	0	0	2	0.0
Wallace Road		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**2**	**0**	**0**	**0**	**2**	0.0
Sawyer Passway	22W1	2,139	0	0	0	0	0	0	1	0	0	0	1	2,139.0
Sawyer Passway	22W2	2	0	0	0	0	0	0	1	0	0	0	1	2.0
Sawyer Passway	22W3	21	0	0	0	0	0	0	1	0	0	0	1	21.0
Sawyer Passway	22W8	2	0	0	0	0	0	0	1	0	0	0	1	2.0
Sawyer Passway	22W10	0	0	0	0	0	0	0	1	0	0	0	1	0.0
Sawyer Passway	22W11	8	0	0	0	0	0	0	1	0	0	0	1	8.0
Sawyer Passway	22W12	1	0	0	0	0	0	0	1	0	0	0	1	1.0
Sawyer Passway	22W17	46	0	0	0	0	0	0	1	0	0	0	1	46.0
Sawyer Passway		**2,219**	**0**	**0**	**0**	**0**	**0**	**0**	**8**	**0**	**0**	**0**	**8**	277.4
River Street	25W27	1,236	0	0	0	0	0	0	1	0	0	0	1	1,236.0
River Street	25W28	644	0	0	0	0	0	0	1	2	0	0	3	214.7
River Street	25W29	3	0	0	0	0	0	0	1	0	0	0	1	3.0
River Street		**1,883**	**0**	**0**	**0**	**0**	**0**	**0**	**3**	**2**	**0**	**0**	**5**	376.6
Lunenburg	30W30	1,445	0	0	0	0	14	14	1	4.5	0	0	5.5	115.6
Lunenburg	30W31	1,720	0	1	0	0	15	16	1	4	0	0	5	132.3
Lunenburg		**3,165**	**0**	**1**	**0**	**0**	**29**	**30**	**2**	**8.5**	**0**	**0**	**10.5**	124.1
Pleasant Street	31W34	1,289	0	0	0	0	0	0	1	0	0	0	1	1,289.0
Pleasant Street	31W37	1,254	0	0	0	0	0	0	1	8	0	0	9	139.3
Pleasant Street	31W38	1,293	0	0	0	0	0	0	1	3	0	0	4	323.3
Pleasant Street		**3,836**	**0**	**0**	**0**	**0**	**0**	**0**	**3**	**11**	**0**	**0**	**14**	274.0
Rindge Road	35W36	819	0	0	0	0	0	0	1	3	0	0	4	204.8
Rindge Road		**819**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**3**	**0**	**0**	**4**	204.8

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			Partially Automated Devices						Fully Automated Devices					
Substation	**Circuit**	**Customers**	**Feeder Breakers** [Note 1]	**Distribution Reclosers, etc.** [Note 2]	**Padmount Switchgear**	**Network Transformers/ Protectors**	**Capacitors & Regulators** [Note 3]	**Partially Automated Device Sub-Totals**	**Feeder Breakers** [Note 1]	**Distribution Reclosers, etc.** [Note 2]	**Padmount Switchgear**	**Network Transformers/ Protectors**	**Fully Automated Device Sub-Totals**	**System Automation Saturation**
West Townsend	39W18	1,991	0	0	0	0	7	7	1	4	0	0	5	234.2
West Townsend	39W19	1,349	0	0	0	0	7	7	1	2	0	0	3	207.5
West Townsend		**3,340**	**0**	**0**	**0**	**0**	**14**	**14**	**2**	**6**	**0**	**0**	**8**	222.7
Summer Street	40W38	37	0	0	0	0	0	0	1	0	0	0	1	37.0
Summer Street	40W39	373	0	0	0	0	1	1	1	1	0	0	2	149.2
Summer Street	40W40	1,639	0	2	0	0	11	13	1	1.5	0	0	2.5	182.1
Summer Street	40W42	2,330	0	0	0	0	4	4	1	0.5	0	0	1.5	665.7
Summer Street	1303	0	0	0	0	0	0	0	1	0	0	0	1	0.0
Summer Street	1309	0	0	0	0	0	0	0	1	0	0	0	1	0.0
Summer Street		**4,379**	**0**	**2**	**0**	**0**	**16**	**18**	**6**	**3**	**0**	**0**	**9**	243.3
Princeton Road	50W51	657	0	0	0	0	0	0	1	0	0	0	1	657.0
Princeton Road	50W53	1	0	0	0	0	0	0	1	0	0	0	1	1.0
Princeton Road	50W54	0	0	0	0	0	0	0	1	0	0	0	1	0.0
Princeton Road	50W55	190	0	0	0	0	0	0	1	0	0	0	1	190.0
Princeton Road	50W56	155	0	0	0	0	0	0	1	1	0	0	2	77.5
Princeton Road		**1,003**	**0**	**0**	**0**	**0**	**0**	**0**	**5**	**1**	**0**	**0**	**6**	167.2
	Total Customers	**31,319**					**Total Partially Automated Devices**	**73**				**Total Fully Automated Devices**	**80**	**268.8**

Note 1: Includes both breakers and reclosers that are used as substation circuit terminals. Does not include other substation breakers or reclosers.

Note 2: Includes distribution reclosers, sectionalizers, automated line switches, S&C IntelliRupters and Siemens Fusesavers.
Does not include capacitor bank switches.
Single controls for multi-phase banks are counted as one.

Note 3: Does not include substation capacitor banks, transformer LTCs or bus regulators.
Single-phase regulator controls are counted individually, even if regulators are part of a multi-phase bank.

Appendix 3

Number/Percentage of Circuits with Installed Sensors

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Substation	Circuit	Number of Sensors By Type: Feeder Breakers [Note 1]	Distribution Reclosers, etc. [Note 2]	Padmount Switchgear	Network Transformers/ Protectors w/ full SCADA	Network Transformers/ Protectors w/ monitoring, no control	Feeder Meters [Note 3]	Capacitors & Regulators [Note 4]	Line Sensors	Fault Indicators	other Voltage Sensing	Sensor Sub-Totals
Beech Street	1W1	1	0	0	0	0	0	0	0	0	1	2
Beech Street	1W2	1	1	0	0	0	0	0	0	0	0	2
Beech Street	1W4	1	1	0	0	0	0	0	0	0	0	2
Beech Street	1W6	1	0	0	0	0	0	0	0	0	0	1
Beech Street		**4**	**2**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**7**
Canton Street	removed from service											---
Canton Street	removed from service											---
Canton Street	11W11	1	0	0	0	0	0	0	0	0	0	1
Canton Street	11W12	1	0.5	0	0	0	0	0	0	0	0	1.5
Canton Street		**2**	**0.5**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**2.5**
Townsend	15W14	1	1	0	0	0	0	0	0	0	0	2
Townsend	15W15	1	0	0	0	0	0	0	0	0	0	1
Townsend	15W16	1	0	0	0	0	0	9	9	0	0	19
Townsend	15W17	1	0	0	0	0	0	1	3	0	0	5
Townsend		**4**	**1**	**0**	**0**	**0**	**0**	**10**	**12**	**0**	**0**	**27**
Nockege	20W22	1	0	0	0	0	0	0	0	0	5	6
Nockege		**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**5**	**6**
Wallace Road	1341	2	0	0	0	0	0	0	0	0	0	2
Wallace Road		**2**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**2**
Sawyer Passway	22W1	1	0	0	0	0	0	0	0	0	4	5
Sawyer Passway	22W2	1	0	0	0	0	0	0	0	0	0	1
Sawyer Passway	22W3	1	0	0	0	0	0	0	0	0	0	1
Sawyer Passway	22W8	1	0	0	0	0	0	0	0	0	0	1
Sawyer Passway	22W10	1	0	0	0	0	0	0	0	0	0	1
Sawyer Passway	22W11	1	0	0	0	0	0	0	0	0	0	1
Sawyer Passway	22W12	1	0	0	0	0	0	0	0	0	0	1
Sawyer Passway	22W17	1	0	0	0	0	0	0	0	0	0	1
Sawyer Passway		**8**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**4**	**12**
River Street	25W27	1	0	0	0	0	0	0	0	0	4	5
River Street	25W28	1	2	0	0	0	0	0	0	0	1	4
River Street	25W29	1	0	0	0	0	0	0	0	0	0	1
River Street		**3**	**2**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**5**	**10**
Lunenburg	30W30	1	4.5	0	0	0	0	14	9	0	0	28.5
Lunenburg	30W31	1	4	0	0	0	0	15	11	0	0	31
Lunenburg		**2**	**8.5**	**0**	**0**	**0**	**0**	**29**	**20**	**0**	**0**	**59.5**
Pleasant Street	31W34	1	0	0	0	0	0	0	0	0	3	4
Pleasant Street	31W37	1	8	0	0	0	0	0	0	0	0	9
Pleasant Street	31W38	1	3	0	0	0	0	0	0	0	0	4
Pleasant Street		**3**	**11**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**3**	**17**

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Substation	Circuit	Number of Sensors By Type										
		Feeder Breakers [Note 1]	Distribution Reclosers, etc. [Note 2]	Padmount Switchgear	Network Transformers/ Protectors w/ full SCADA	Network Transformers/ Protectors w/ monitoring, no control	Feeder Meters [Note 3]	Capacitors & Regulators [Note 4]	Line Sensors	Fault Indicators	other Voltage Sensing	Sensor Sub-Totals
Rindge Road	35W36	1	3	0	0	0	0	0	0	0	1	5
Rindge Road		**1**	**3**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**5**
West Townsend	39W18	1	4	0	0	0	0	7	6	0	0	18
West Townsend	39W19	1	2	0	0	0	0	7	8	0	0	18
West Townsend		**2**	**6**	**0**	**0**	**0**	**0**	**14**	**14**	**0**	**0**	**36**
Summer Street	40W38	1	0	0	0	0	0	0	0	0	0	1
Summer Street	40W39	1	1	0	0	0	0	1	1	0	0	4
Summer Street	40W40	1	2.5	0	0	0	0	11	8	0	0	22.5
Summer Street	40W42	1	0.5	0	0	0	0	4	2	0	0	7.5
Summer Street	1303	1	0	0	0	0	0	0	0	0	0	1
Summer Street	1309	1	0	0	0	0	0	0	0	0	0	1
Summer Street		**6**	**4**	**0**	**0**	**0**	**0**	**16**	**11**	**0**	**0**	**37**
Princeton Road	50W51	1	0	0	0	0	0	0	0	0	0	1
Princeton Road	50W53	1	0	0	0	0	0	0	0	0	0	1
Princeton Road	50W54	1	0	0	0	0	0	0	0	0	0	1
Princeton Road	50W55	1	0	0	0	0	0	0	0	0	1	2
Princeton Road	50W56	1	1	0	0	0	0	0	0	0	0	2
Princeton Road		**5**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**7**

Total number of Substations	13
Total number of Substations with Sensors	13
% of Substation with Sensors	100.0%
Total number of Circuits	42
Total number of Circuits with Sensors	42
% of Circuits with Sensors	100.0%

Note 1: Includes both breakers and reclosers that are used as substation circuit terminals. Does not include other substation breakers or reclosers.

Note 2: Includes distribution reclosers, sectionalizers, automated line switches, S&C IntelliRupters and Siemens Fusesavers.
Does not include capacitor bank switches.
Banks of multiple single-phase devices are counted as one.

Note 3: Includes metering or other IEDs applied at substation circuit terminals. Does not include other substation meters or IEDs.

Note 4: Does not include substation capacitor banks, transformer LTCs or bus regulators.

Appendix 4

Variance Analysis

NOTE:

D.P.U. APPENDIX 4 PROVIDED IN

PDF FORMAT

Appendix 5

Grid Modernization Factor Spreadsheet

NOTE:

D.P.U. APPENDIX 5 PROVIDED IN EXCEL FORMAT