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

2023
Grid Modernization Plan
Annual Report

Massachusetts Department of Public Utilities
D.P.U. 24-40

Dated: 7-1-2024

Table of Contents

List of Appendices

List of Tables

Acronyms

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

DPU – 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

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 DPU 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.

On January 25, 2023, the Department issued a memorandum which assigned the docket number D.P.U. 23-30 for the Companies calendar year 2022 annual report filings 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 Companies calendar year 2023 annual report filings 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.

This 2023 Grid Modernization Annual Report and associated templates are filed pursuant to the Department's orders in D.P.U 21-80 as well as the memorandums in D.P.U. 23-30 and D.P.U. 24-40. This report is designed to demonstrate that the Company is making measurable progress towards 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 been working towards implementing these projects since the original GMP was approved in 2018 and Term 2 was approved in 2022.

This Annual Grid Modernization Report covers activities in 2023 and describes the Company's progress towards 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 is making significant progress towards the design and implementation of its Grid Modernization plan. 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 2023, the Company was successful in continuing the implementation of its ADMS system, commencing the evaluation testing of the VVO on the circuits emanating from the Townsend Substation (commissioned in 2022), commissioning of VVO equipment for the Summer St. substation circuits, further development of SCADA, further expansion of the field area network with every VVO device installed in the field and an upgrade to our GIS software to facilitate the Mobile Damage Assessment project.

The Company also experienced some challenges associated with the supply chain of equipment which delayed the implementation of SCADA and VVO projects.

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 and FAN communication for the area of our system served by Townsend and Summer Street substations. The implementation of substation SCADA expansion has been progressing. In 2023, all required VVO equipment on the circuits emanating from the Summer St. substation was commissioned and put in service, and the installation of the required VVO equipment from the Lunenburg Substation was started. In addition, the "On/Off" evaluation testing of the VVO system with the ADMS was started on the circuits from the Townsend Substation. This testing is planned to continue for more than nine months and is expected to be complete in 2024. 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 has placed the integration of AMI and OMS on a temporary hold as other issues and decisions are made.

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 includes two projects from the Company's GMP. The first project is a Supervisory Control and Data Acquisition (SCADA) project to expand the coverage and functionality of Company's SCADA system. The second project is to further integrate OMS with the Company's AMI system.

The Company has completed the SCADA implementations at the first six substations in its GMP (Rindge Road, Townsend, Beech Street, Lunenburg, Nockege and River Street). Implementation at a seventh substation is in the construction stage (Princeton Road), with completion anticipated in 2024. Additionally, an eighth substation (Canton Street), is in the design and material procurement stages also with completion anticipated in 2024.

The OMS integration with AMI project was placed on temporary hold in late 2021 and remains on hold. There were two main challenges with respect to the AMI/OMS integration project which resulted in the Company placing the project on temporary hold: 1) network configuration of the ADMS system and 2) information from our AMI vendor they are discontinuing PLX technology. The Company has selected Landis & Gyr to provide its replacement AMI system. See D.P.U. 24-54, Exhibit KSJG-1 at 11 (April 16, 2024). Therefore, the Company expects to continue with this integration after the new AMI system is installed.

<u>Volt/VAr Optimization Investment Category</u>
The equipment for all circuits emanating from two substations have been installed and commissioned. This equipment is currently operating under local automatic control. The equipment is communicating to the ADMS system, with the produced value for one substation currently being evaluated. Equipment for a third and fourth substation is currently being installed and commissioned. The material for the fifth substation has been ordered and are expected to be received in 2025. 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 full implementation of the central analysis and control through the ADMS system for the first two substations (Townsend and Summer St.) is complete. The evaluation testing of the Townsend Substation is complete. Due to major upgrades being complete on the electric system that will affect the ADMS operation, the evaluation testing of the Summer St. substation is on hold and is expected to begin in November, 2024.

<u>Advanced Distribution Management System Investment Category</u>
The Company has completed the modelling and implemented unbalanced loadflow of two substations (nine circuits) in the ADMS production environment. ADMS/VVO when enabled is setting all regulator bandcenters and

controlling all capacitor banks on the circuit to minimize losses and system demand. Formal "On/Off" testing of one substation took place in 2023 and is expected to be completed in the first quarter of 2024. The evaluation testing of the second substation is expected to start in 2023 and be complete in 2024.

Unitil currently plans to start deploying DERMS in 2025 after the initial ADMS deployment is complete. It is expected to take two years to implement DERMS and integrate with Unitil owned DER facilities.

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 will include FAN capital costs in the VVO project and stop reporting the FAN project as a separate project.

Workforce Management Investment Category

After several meetings and weeks of deliberation by the project team, it was ultimately decided that the best solution was the Mobile Information Management System (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. Efforts needed to complete the project including system and user acceptance testing, training and full implementation are expected to be completed by in 2024.

DER Mitigations

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 design and procurement stages started in 2022 for the first of these overvoltage protection improvement projects as part of the GMP (Canton Street substation), and in 2023 for the next two (Summer Street and Sawyer Passway substations). Implementation is expected to be completed in 2024 for all three of these.

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 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 identifies this information as a variation from the previously approved AMI project in the 2022-2025 plan. As such, the Company has filed a petition with the Department (DPU 24-54) to revise the scope of the original AMI project and obtain preauthorization of certain AMI investments in connection with the revised scope. The capital investments and O&M costs presented in this report represent the revised AMI project scope.

Customer Engagement and Experience

Work completed in 2022 consists of the Apogee Rate Comparison Tool, The Customer Experience Management Solution and Utility Bill Redesign.

For the Apogee Rate Comparison Tool project, the Company contracted with Apogee, conducted functional and integration testing and deployed the tool in our New Hampshire subsidiary. This tool is a rate-comparison calculator that integrates with billing history and load profiles to calculate the customer's monthly and annual energy costs, which allows them to choose the rate plan most suited to their homes, flexibility, and lifestyles. Additionally, this tool is an EV Calculator which allows customers to utilize multiple sliders with EV information and personal driving variabilities to assist customers to understand how an EV time varying rate may benefit their purchase of an electric vehicle. This tool has been made available to FG&E's customers in conjunction with the deployment of the EV TOU rates.

For the Customer Experience Management Solution project, the Company contracted with Systems & Software (existing CIS vendor) and began functional testing of the solution in 2022. This system is an integrated web portal that will add self-service options enabling customers to better manage their energy usage and account information. The solution additionally will include a mobile app, artificial intelligence and chat features, coupled together with a robust notification engine to proactively alert customers regarding payment activity, increases in usage, outage notifications, and the status of scheduled appointments – all of which will provide a responsive integrated web experience for our customers.

For the Utility Bill Redesign project, the Company conducted thorough functional and integration testing in 2022 for this project that transitions our bill from a system generated bill using set designs on pre-printed billing forms to a dynamic bill print job. Personalizing messaging by customer class, location and interests in products and services can all be attained through a more dynamic billing product. This change will utilize color, different fonts, graphs and other tools will allow the Company to draw attention to key information serving as valuable educational opportunities for various new products and services, rate plans, and behind the meter partnerships.

Data Sharing Platform

Unitil Corporation subsidiary, Unitil Energy Systems (UES) located in New Hampshire ("NH") has filed a proposed approach for data sharing in NH PUC Docket No. DE 19-197. Unitil Service Corporation has taken a lead on developing a proposal for a data sharing platform and if found to be successful, Unitil Service Corporation would provide the data sharing platform to the Company as well.

In March of 2022, the 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. The data platform will enable customers, as well as third-party energy providers, to access energy consumption data from all regulated electric and natural gas utilities through a single secure portal.

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)

As previously described, the Company has been working on more detailed design and analysis required before it can confidently implement the GMP capital investments identified in its GMP. The "2022-2025 Plan" represents the planned spending in 2022 and the following years. The "2022-2023 Actual / 2024-2025 Forecast" Plan Year represents the actual spending for 2022-2023 and the most up to date forecast spending for 2024-2025. Table 1 below demonstrates the actual spending versus the plan.

	Actual/Forecasted Capital Spending			
	2022	2023	2024	2025
Monitoring and Control				
SCADA				
2022-2025 Plan	$ 625,000	$ 186,000	$ 218,000	$ 100,000
2022-2023 Actual / 2024-2025 Forecast	$ 101,337	$ 208,870	$ 640,000	$ 33,000
OMS Integration with AMI				
2022-2025 Plan	$ 155,000	$ 0	$ 0	$ 0
2022-2023 Actual / 2024-2025 Forecast	$ 0	$ 0	$ 0	$ 64,000
Volt VAr Optimization				
VVO				
2022-2025 Plan	$ 270,000	$ 675,000	$ 2,070,000	$ 2,400,000
2022-2023 Actual / 2024-2025 Forecast	$ 249,795	$ 499,290	$ 490,653	$ 797,450
Advanced Distribution Management System				
ADMS/DERMS				
2022-2025 Plan	$ 400,000	$ 250,000	$ 175,000	$ 125,000
2022-2023 Actual / 2024-2025 Forecast	$ 58,783	$ 103,435	$ 50,000	$ 125,000
Field Area Network				
Field Area Network				
2022-2025 Plan	$ 198,000	$ 121,000	$ 285,000	$ 179,000
2022-2023 Actual / 2024-2025 Forecast	$ 184,380	$ 0	$ 0	$ 0
Workforce Management				
Mobile Platform Damage Assessment				
2022-2025 Plan	$ 50,000	$ 50,000	$ 50,000	$ 50,000
2022-2023 Actual / 2024-2025 Forecast	$ 25,048	$ 101,096	$ $66,534	$ 50,000
DER Integration				
DER Mitigations				
2022-2025 Plan	$ 289,000	$ 753,000	$ 0	$ 0
2022-2023 Actual / 2024-2025 Forecast	$ 3,394	$ 91,629	$ 863,000	$ 0
Advanced Metering Functionality				
AMI				
2022-2025 Plan	$ 2,345,532	$ 4,565,134	$ 3,977,770	$ 339,080
2022-2023 Actual / 2024-2025 Forecast	$ 76,270	$ 0	$ 4,580,922	$ 6,672,457
Customer Engagement				
Customer Engagement and Experience				
2022-2025 Plan	$ 241,000	$ 91,000	$ 0	$ 566,000
2022-2023 Actual / 2024-2025 Forecast	$ 31,238	$ 9,120	$ 0	$ 0
Data Sharing				
2022-2025 Plan	$ 466,000	$ 78,000	$ 0	$ 0
2022-2023 Actual / 2024-2025 Forecast	$ 0	$ 0	$ 466,000	$ 78,000

Total				
2022-2025 Plan	$5,039,532	$6,769,134	$6,775,770	$3,759,080
2022-2023 Actual / 2024-2025 Forecast	$730,245	$1,013,440	$7,157,109	$7,819,907

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 2023 was below the plan through 2023 and the overall forecasted spending through 2025 is below the original 2022 – 2025 plan.

The Company identified an error in the 2022 spending for the SCADA project reported in last year's 2022 annual report. Actual spending for the SCADA project at one location was inadvertently omitted in that report. The corrected 2022 spending for the SCADA project is reported in the table above.

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 2023.

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 actual and future years, these costs are included in the VVO project as the modems are commissioned with the VVO field equipment.

	Actual/Forecasted Incremental O&M Spending			
	2022	2023	2024	2025
Monitoring and Control				
SCADA				
2022-2025 Plan	$ 0	$ 0	$ 0	$ 0
2022-2023 Actual / 2024-2025	$ 0	$ 0	$ 0	$ 0
OMS Integration with AMI				
2022-2025 Plan	$ 0	$ 11,000	$ 11,000	$ 11,000
2022-2023 Actual / 2024-2025	$ 0	$ 0	$ 0	$ 11,000
Volt VAr Optimization				
VVO				

2022-2025 Plan	$ 5,000	$ 5,000	$ 5,000	$ 5,000
2022-2023 Actual / 2024-2025	$ 8,208	$ 18,080	$ 18,500	$ 22,176
Advanced Distribution Management System				
ADMS/DERMS				
2022-2025 Plan	$ 174,000	$ 176,000	$ 177,000	$ 178,000
2022-2023 Actual / 2024-2025	$ 60,706	$ 106,1333	$ 177,000	$ 178,000
Field Area Network				
Field Area Network				
2022-2025 Plan	$ 10,000	$ 10,000	$ 10,000	$ 10,000
2022-2023 Actual / 2024-2025	$ 10,000	$ 26,328	$ 27,118	$ 26,650
Workforce Management				
Mobile Platform Damage Assessment				
2022-2025 Plan	$ 50,000	$ 50,000	$ 50,000	$ 50,000
2022-2023 Actual / 2024-2025	$ 0	$ 16,000	$ 16,000	$ 16,000
DER Integration				
DER Mitigation				
2022-2025 Plan	$ 0	$ 0	$ 0	$ 0
2022-2023 Actual / 2024-2025	$ 0	$ 0	$ 0	$ 0
Advanced Metering Functionality				
AMI				
2022-2025 Plan	$ 0	$ 0	$ 0	$ 0
2022-2023 Actual / 2024-2025	$ 0	$ 0	$ 0	$ 132,081
Customer Engagement				
Customer Engagement and Experience				
2022-2025 Plan	$ 16,151	$ 91,000	$ 16,151	$ 66,000
2022-2023 Actual / 2024-2025	$16,151	$16,151	$ 0	$ 0
Data Sharing				
2022-2025 Plan	$ 0	$ 0	$ 0	$ 0
2022-2023 Actual / 2024-2025	$ 0	$ 0	$ 0	$ 0
Third Party M&V Evaluation				
2022-2025 Plan	$ 75,000	$ 75,000	$ 75,000	$ 75,000
2022-2023 Actual / 2024-2025	$ 10,193	$ 75,000	$ 75,000	$ 75,000
Total				
Total				
2022-2025 Plan	$ 330,151	$ 418,000	$ 344,151	$ 395,000
2022-2023 Actual / 2024-2025	$ 105,258	$ 1,212,892	$ 313,618	$ 460,907

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 O&M expenses.

2 PROGRAM IMPLEMENTATION OVERVIEW

The Company has 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 Vice President of Engineering. 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 2023. See D.P.U. 24-54.

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 Vice President of Engineering. 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 2023 Evaluation to be issued in July 2024.

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; and provides updated projections for the remainder of the three year term.

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 would be 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[1]. 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

3.1.1 MONITORING/CONTROL

The Monitoring and Control investment category includes two projects from the Company's GMP. The first project is to expand the coverage and functionality of Company's SCADA system. The second project is to further integrate OMS with the Company's AMI system.

3.1.1.1 SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA)

The objective of this 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.

[1] 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.

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.

3.1.1.1.1 Description of Work Completed

The Company has completed GMP-related SCADA implementations at six substations in its GMP (Rindge Road, Townsend, Beech Street, Lunenburg, Nockege and River Street). Implementation at a seventh substation is in the construction stage (Princeton Road), with completion anticipated in 2024. As of the end of 2023, implementation at an eighth substation was in the design and material procurement stages (Canton Street), also with completion anticipated in 2024.

3.1.1.1.2 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.

3.1.1.1.3 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. Table 7 provides the planned implementation and spending for the remainder of this term of the GMP.

	2022		2023		2024	2025
Year	Plan	Actual	Plan	Actual	Plan	Plan
Capital Costs	$625,000	$101,337	$334,405	$208,870	$640,000	$33,000
O&M Costs	$0	$0	$0	$0	$0	$0
Total Costs	$625,000	$101,337	$334,405	$208,870	$640,000	$33,000

Table 7 – SCADA 2022-2023 Actual / 2024-2025 Forecast Spending

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.

3.1.1.1.4 Performance on Implementation/Deployment

The Company expects to begin construction in 2024 on the eighth of its GMP-related substation SCADA implementations.

3.1.1.1.5 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.

3.1.1.1.6 Description of Capability Improvement

When the SCADA deployment is complete at each substation the following functionality is expected to be present:

- 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

3.1.1.1.7 Key Milestones

Full SCADA implementation is planned to be completed for Princeton Road and Canton Street substations in 2024, and for Pleasant Street substation in 2025.

3.1.1.1.8 Updated Projections for Remainder of the Three-year Term

As described above, implementation is planned to be completed for Princeton Road and Canton Street substations in 2024, and for Pleasant Street substation in 2025

3.1.1.1.9 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	11W10 (future) 11W11	LTC controls & SCADA planned for completion 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 planned for completion 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 planned for completion in 2024 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. Possible future modifications for energy measurements for Grid Mod metrics, but not explicitly planned at this time.
Summer Street	40W38 40W39 40W40 40W42	Pre-existing partial SCADA. Full SCADA completed in 2020 (non-GMP).
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

3.1.1.2 OMS INTEGRATION WITH AMI

This is a software project to enhance the current AMI to OMS interface. Unitil has already implemented an AMI system across its service territories. This enhanced integration will provide improved ability for all AMI meters to communicate with the OMS system in a more reliable manner resulting in greater confidence in the data presented. This enhanced data will be used in the OMS outage engine to help improve outage predictions, including which device has isolated the fault and what customers have been restored.

Unitil's AMI system provides information on outages for every meter on the system. This project is designed to improve the integration of outage information from meters into the OMS outage prediction engine, thereby improving the outage prediction process, reducing false positives and improving the ability to identify the location of nested outages.

Unitil's OMS system relies on customer outage calls processed by the IVR system, web outage form entries, and manual entries of customer and municipal calls to determine the location and extent of outages. Most outages are reported by only a small percentage of customers contributing to the outage information (typically, only 1-2% of the customers notify Unitil when they are out of power). This small percentage of customer notifications may lead to an erroneous outage location and extent, or delay the field trouble shooting process.

Unitil's AMI system is currently integrated with OMS as a "view only" overlay. The AMI system communicates with all meters through a parallel channel power line carrier (PLC) system. Essentially, the system continuously communicates with all the meters on the system while data collectors in the substations transmit meter status to the head end software system called the Command Center. Changes in meter status are shared through live integration with the OMS where they can be represented visually. Because communication with meters could be lost for reasons other than an outage (e.g., noise on power line, loss of AMI network communications), Unitil does not use this information in the algorithm for modeling outages in OMS. Instead, the visual AMI information is presented in OMS to help determine the extent of the outage (i.e. all outage meters go "lost" or red when they lose power) and the extent of restoration (i.e. all restored meters restored become "found" or green).

The figure below shows a partial restoration of an outage. The red icons indicate customers still out, the green are customers that have been restored.

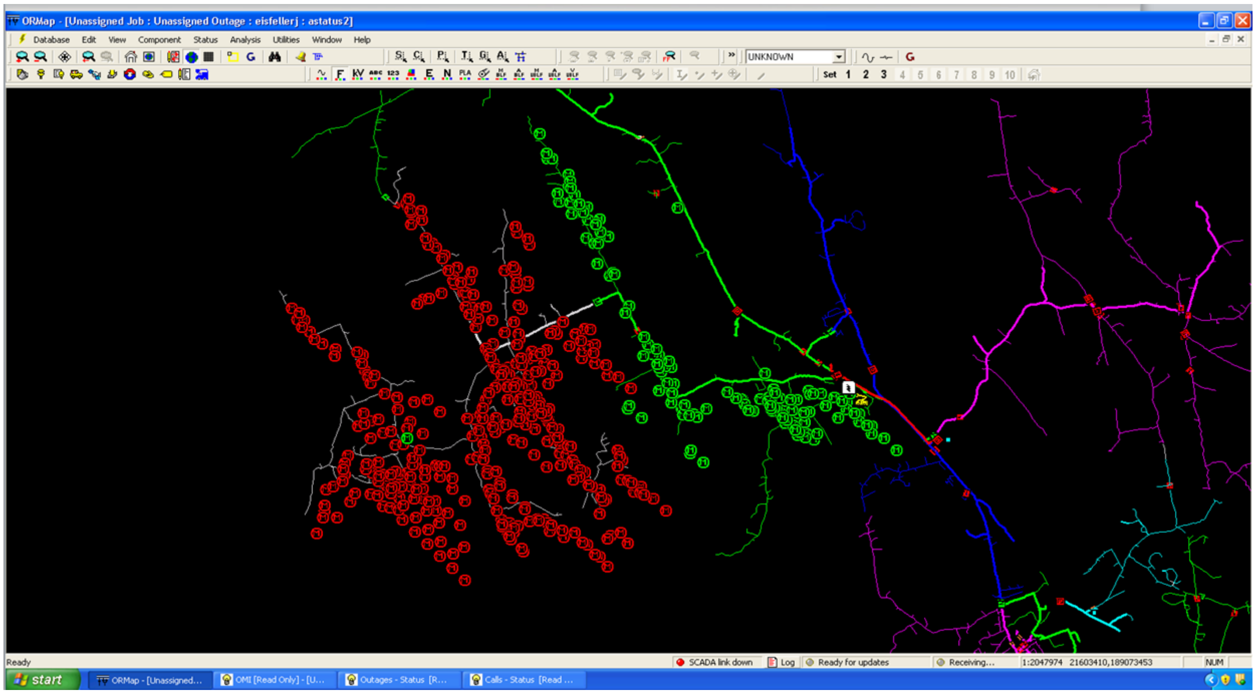

Figure 1: Unitil's AMI Meters in OMS

Unitil is developing a piece of configurable "middleware" (i.e. software) to analyze AMI status changes along with additional relevant data points, and computing an "AMI Confidence Score" for AMI based customer outage reporting. Based on the configuration of the middleware, suspected outages above the allowed "confidence score threshold" will be treated as "real outages" and reported to OMS as such. Those that fall below the threshold will be logged and sent to OMS for view only. This threshold is adjustable by the dispatcher to allow some level of active customization.

The system will leverage a set of correlating data inputs such as historical outages, low level signal data, modem communications status and weather data along with machine learning models to assist in computing outage confidence.

Unitil has worked closely with its AMI vendor (Landis & Gyr) to identify a combination of data points available on the meter and the AMI collectors along with various correlating data points (environmental and coincident) to build a model that can accurately confirm suspected outages and electronically qualify them.

The project has been broken down into two phases (both are included in the project):

Phase 1 – AMI Confidence Engine & Filter

Although our Landis and Gyr AMI system has functionality to detect and report on meter/ endpoint level outages, the results we see are unreliable to the point that Unitil has chosen not to directly integrate the AMI data for outage model calculations. A meter black list construct was implemented where known bad reporting endpoints could be grouped and ignored by any auto outage detection. However, there is no easy way for Unitil to dynamically move meters on and off this "outage reporting black list", which makes it a largely static list. If, for example, we make improvements to a network segment of previous blacklisted meters; even though these meters could likely better participate in the AMI auto detection after the upgrade is completed, they will not be able to, because they are part of this hardcoded black list.

Unitil is making use of this automatic detection process and accompanying data in an effort to improve our ability to detect and respond to customer outages. Unitil also believes that it can augment the existing Landis & Gyr detection algorithm with an additional algorithm leveraging readily available data to correlate and further qualify (by way of a "Confidence Score") suspected outages.

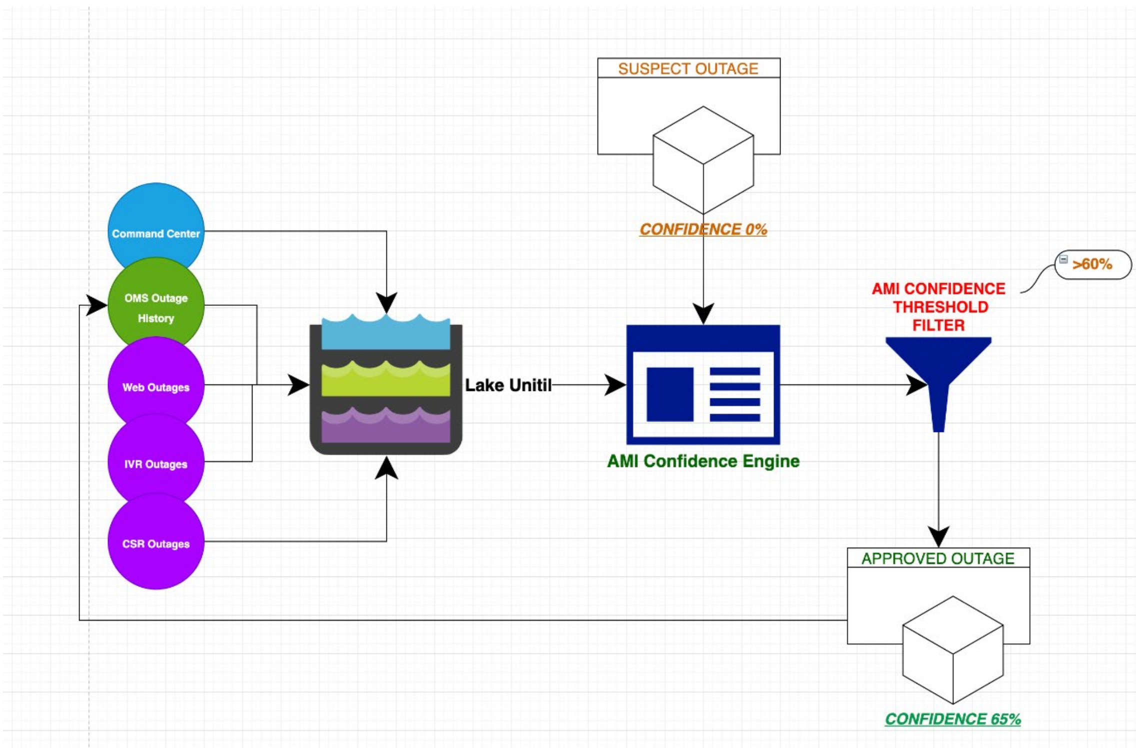

Figure 2: AMI/OMS Phase 1 Diagram

ACE Filter - The ACE Filter is a software service that is responsible for evaluating the confidence score attached to an outage and determining if the score meets or exceeds the configurable confidence threshold (dispatchers would be able to dynamically adjust this threshold up or down). Any outage that meets or exceeds the threshold is allowed through the Filter. Any outage failing to meet the criteria is rejected, logged and a notification is sent. No changes would be required to the core OMS functionality as the filter would handle pre- screening outages before sending them along to OMS.

Lake Unitil - Our data warehousing "lake", will contain data from our Command Center, OMS and enQuesta systems to start. The application development team will build out data load scripts to populate and maintain this Data Lake. It is helpful to think of a data lake as a large data warehouse in the cloud that contains data in a variety of different formats (*XML, flat unstructured data files, CSV and traditional relational data). The ACE will use the data contained in this lake to make its confidence scoring decisions. In later phases, additional data points such as vegetation, social media, behind the meter status and weather could be added to the data lake and augment the algorithm.

Phase 2 – Additional Data Sources

In this phase of the development we will be including additional data sources into the confidence interval. Specifically, this plan includes the collection and combination of data sources for weather as well as signal to noise ratio (directly from AMI Collectors) into the confidence engine. Quality control, testing and deployment, as well as ongoing support of the system are included.

This project will combine AMI status information, modem status information, and current outage input data (IVR, Web, and manual entries), and process this information through a series of software filters and logic to allow AMI information to be used in the outage algorithm. The goal will be to develop this filter to the point at which there is high confidence in the result (i.e., the AMI status change is a result of an actual outage). If a high confidence is achieved, the AMI data will allow Unitil to determine the probable location and extent of an outage in a shorter timeframe, resulting in improvements in outage response time estimates and related customer communications.

The proposed upgrade will allow AMI outage information to be used directly in the AMI outage prediction engine for outage reporting if the AMI status change has an associated high confidence factor. This AMI information should improve timeliness of outage detection, dispatch, extent and restoration.

3.1.1.2.1 Description of Work Completed

This project was placed on temporary hold in late 2021 and remains on hold.

There were two main challenges with respect to the AMI/OMS integration project which resulted in the Company placing the project on temporary hold: 1) network configuration of the ADMS system and 2) information from our AMI vendor they are discontinuing PLX technology.

<u>Network Configuration of ADMS</u> – Cyber security is critical when monitoring and controlling field devices. The Company went through a rigorous process to design and implement a secure network environment that is separate from the Company's corporate network.

The AMI/OMS project was started prior to the ADMS project and requires internal IT staff to work closely with the Company's third-party integrator. This project relies on efficient data flow from the individual meter collectors in the field and into the OMS system which is now part of the ADMS system.

As the AMI/OMS Integration continued, the Company determined that the ADMS secure network needed to be established before continuing with the AMI/OMS Integration project. The AMI/OMS project was placed on hold in the second half of 2021 while the Company focused on developing the secure ADMS network.

Discontinuation of PLX Technology – The Company's filed its 2022-2025 Grid Modernization Plan on July 1, 2021. The Company's filing included an AMI plan, consistent with Department directives. The Company proposed a meter replacement plan to transition from TS2 meters to Gridstream PLX technology.

In late June, 2022, the Company was notified that Landis+Gyr intended to discontinue its 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. 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 2022 – November 2022 to 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 meters as well as the communications technology prior to 2029.

The Company decided the prudent path forward is to issue an RFP and complete a competitive bidding process for a new AMI system. The RFP was issued on December 22, 2023 with responses due March 1, 2023. Unitil completed a detailed review and negotiation process and selected Landis+Gyr as the metering vendor based upon the use of their Revelo meter. The communications network for the selected AMI meters is an IP-based 900 MHz RF mesh network. Furthermore, the head end system will be replaced in conjunction with the meter replacement, as the Revelo meters are not capable of communicating with the system as currently deployed. The replacement head end system will be a cloud based software as a service ("SaaS"), which will allow the Company to operate both the new and old systems in parallel while the meters transition to new technology. .

3.1.1.2.2 Lessons Learned/Challenges and Successes

While we could not have planned for the discontinuation of PLX by our vendor, we could have likely avoided early challenges with data access by scheduling this work to follow the ADMS roll-out rather than attempting the project execution contemporaneously.

3.1.1.2.3 Actual vs. Planned Implementation and Spending

This project remains on hold in 2024. The Company will begin installation of AMI replacement meters in 2024 and expects to complete the replacement in 2025. The Company expects to resume work on the AMI / OMS integration in 2025.

	2022		2023	2023	2024	2025
Year	Plan	Actual	Plan	Actual	Plan	Plan
Capital Costs	$155,000	$ 76,270	$0	$0	$0	$64,000
O&M Costs	$0	$0	$0	$0	$0	$11,000
Total Costs	$155,000	$ 76,270	$0	$0	$0	$75,000

Table 9 – AMI/OMS Integration 2022-2023 Actual / 2024-2025 Forecast Spending

3.1.1.2.4 Performance on Implementation/Deployment

This project was placed on temporary hold in late 2021 and remains on hold. Information on performance will be provided when the system goes live. The Company has selected Landis & Gyr to provide its replacement AMI system. Therefore, the Company expects to continue with this integration after the new AMI system is installed.

3.1.1.2.5 Description of Benefits Realized as the Result of Implementation

The Company has not realized the benefits identified as part of the GMP because this project is not yet complete. The theory is that the outage information from the AMI system will allow the Company to know about the outage without having to rely on a customer phone call through the IVR system. It is expected that the AMI system on average will be five (5) minutes faster than customer calls for 10% of outages.

3.1.1.2.6 Description of Capability Improvement

The proposed upgrade will allow AMI outage information to be used directly in the AMI outage prediction engine for outage reporting if the AMI status change has an associated high confidence factor. This AMI information should improve timeliness of outage detection, dispatch, extent and restoration.

3.1.1.2.7 Key Milestones

This project was placed on temporary hold in late 2021 and remains on hold.

3.1.1.2.8 Updated Projections for Remainder of the Three-year Term

The Company had no plans for 2023 spending on this project and it remains on hold. The Company will begin installation of AMI replacement meters in 2024 and expects to complete the replacement in 2025. The Company expects to resume work on the AMI / OMS integration in 2025.

3.1.2 VOLT/VAR OPTIMIZATION (VVO)

Volt VAr Optimization (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.

3.1.2.1 VOLT/VAR OPTIMIZATION (VVO)

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.

3.1.2.1.1 Description of Work Completed

The Company has assigned an internal project manager and assembled a project team of internal employees to evaluate and implement a VVO system. Because the VVO system is integrated with the ADMS and likely monitored and controlled through the SCADA system with communication media installed as part of the FAN, the VVO team is coordinating its efforts closely with these other project teams, in developing the VVO project scope and detailed schedule.

The equipment for all circuits emanating from two substations have been installed and commissioned, and a majority of equipment has been commissioned for a third substation. The "On/Off" evaluation testing using the ADMS control of the equipment for the first substation is in process and is expected to be complete in the first quarter of 2024. The evaluation results will be reported in a separate report generated by an independent consultant. All commissioned equipment is currently operating under local automatic control. The equipment is communicating to the ADMS system. The "On/Off" evaluation testing for the second and third substations are expected to commence in 2024. 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. Because of material lead time the ordering of material is planned two years prior to the planned installation. The equipment for the first two substations has been installed and commissioned. The full implementation of the central analysis and control through the ADMS system for these two substations (Townsend and Summer St.) is expected to start this year.

3.1.2.1.2 Lessons Learned/Challenges and Successes

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.

The more efficient process of setting the controls and commission testing has been developed and is expected to reduce the labor costs on future installations.

3.1.2.1.3 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 in 2023.

	2022		2023		2024	2025
Year	Plan	Actual	Plan	Actual	Plan	Plan
Capital Costs	$270,000	$249,795	$675,000	$487,142	$474,000	$651,000
O&M Costs	$5,000	$8,208	$5,000	$18,080	$18,500	$22,176
Total Costs	$275,000	$258,003	$680,000	$505,222	$492,500	$673,176

Table 10 – VVO 2022-2023 Actual / 2024-2025 Forecast Spending

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.

3.1.2.1.4 Performance on Implementation/Deployment

The installation and commissioning of field equipment has been complete at two substations. Although the central control of these devices has not been commissioned, the testing is underway and the equipment is operating automatically using local measurements. The commissioning of the central analysis and control of the equipment for Townsend was completed at the end of 2022 and Summer St. was started in 2023. The commissioning of field equipment from the Lunenburg substation is expected to be complete this year, with commissioning of the central control in 2024 - 2025. The installation of field equipment for the West Townsend substation is also expected to start this year with commissioning of the central control in 2024 - 2025. The commissioning of the central control is planned to extend over nine months including the summer peak months, winter peak months, and the spring of fall light load season.

3.1.2.1.5 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 one 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 expects the evaluation to be complete in 2024.

3.1.2.1.6 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 will be designed to support the VVO program. The software intelligence will be discussed 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.

Although the project does not presently include plans to control customer owned inverters, the Company plans to implement a system with the possibility of controlling inverters along with capacitors, to provide reactive power to the distribution system.

3.1.2.1.7 Key Milestones

The Company has identified the existing field devices and controls that will need to be replaced in order to implement a VVO system and has developed the following replacement plan in line with the prioritized model that is described above. In addition to the existing devices, new installations of monitors and new voltage regulators are planned. The actual number of additional devices is determined 1-2 years prior to the planned installation. Until the actual number of additional devices is determined, an estimate is included based on the circuit size. The year listed below indicates the expected year that the equipment will be installed and VVO implemented.

Year installed	Year VVO Implemented	Substation	LTC Controls	Volt Reg Controls[2]	Cap Bank Controls	Monitors[3]
2021	2022	Townsend	1	6	5	12
2022	2023	Summer Street	1	16	4	30
2024	2024	Lunenburg	0	28	4	25
2023	2025	West Townsend	1	11	3	20
2026	2027	Beech Street/ Rindge Rd.	1	17	7	26
2027	2028	Pleasant Street	1	11	10	22
2027	2028	Princeton Road	2	1	7	8
2028	2029	Sawyer Passway	2	12	0	12
2029	2030	Canton Street	1	6	6	18
2029	2030	River Street	1	5	7	7
2029	2030	Rindge Road	0	10	0	6
2030	2031	Nockege	0	15	1	10

Table 11 – VVO Field Equipment Estimates

[2]Unitil detailed analysis is performed for a given year, the number of voltage regulator controls listed is only the present number installed on the system. Detailed analysis is performed a year prior to planned installation which will identify the quantity of regulators required.

[3] Unitil detailed analysis is performed for a given year, the number of monitors listed is only the present number installed on the system. Detailed analysis is performed a year prior to planned installation.

3.1.2.1.8 Updated Projections for Remainder of the Three-year Term

In 2024-2025, the Company plans to:

- Complete the VVO implementation of four substations in ADMS per the table above.
- Continue installation of the controls and monitors on all circuits emanating from two substations per the table above.

3.1.2.1.9 Feeder Level Narrative

The Company has installed and commissioned VVO devices (regulators, capacitor banks, and monitoring sensors) for the Townsend, Summer St. circuits. The VVO functionality is tested and functional in the ADMS system for both substations. The "on/Off" evaluation testing is expected to be complete in 2024. The majority of equipment for the Lunenburg substation is installed and commissioned. Due to operational issues of some controls, three voltage regulators, although installed, are not yet commissioned. Due to lead-time issues of control and communication equipment, the equipment for the West Townsend substation has not yet been installed and commissioned. The Company plans to have all equipment for Lunenburg and West Townsend installed and commissioned in 2024. 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	2024
Lunenburg	30W30 30W31	2024	2025
West Townsend	39W18 39W19	2024	2025

Table 12 – VVO Schedule Through 2025

3.1.3 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (and DERMS)

The ADMS investment category includes two projects for the Company's GMP. The first project is an ADMS project to allow for more advanced measurement and control of the distribution system. The second project is to implement a Distributed Energy Resource Management System (DERMS) which will enable the Company to improve situational awareness and operational intelligence for DERs. The DERMS functionality is available in the ADMS system the Company is implementing.

3.1.3.1 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (and DERMS)

This project consists of upgrading the Company's current OMS to an ADMS that will support VVO and power flow analysis. In the future the ADMS will also support distribution system automation, including automated distribution switching and fault location, isolation and service restoration (FLISR). The ADMS will also serve as a platform for more advanced modules in the future such as DERMS. The existing system integrations with GIS, CIS, OMS and SCADA will be enhanced to provide the necessary technical information for ADMS to perform the functions described above.

An ADMS is the next step in the evolution of distribution management systems. An ADMS integrates a comprehensive set of monitoring, analysis, control, planning, and informational tools that work together with one common network model. An ADMS merges existing OMS, ADMS, circuit analysis, unbalanced load flow, and SCADA systems together to provide all of the information to one location. An ADMS allows its users, operators, and dispatchers a real-time view of the distribution system. In order for the ADMS to provide benefits, it must be integrated with the some of the Company's other Grid Modernization initiatives including, the FAN, Substation SCADA and VVO projects.

An ADMS system can provide many different functions such as (but not limited to) self-healing automation, control for distributed energy resources, additional SCADA functions across the distribution system, real-time load flow and circuit analysis, demand response, outage restoration, direct load control, network configuration, and VVO.

As provided in the Company's plan, the implementation of ADMS is primarily focused on integration of a VVO system.

Unitil's vision is to utilize ADMS/DERMS to manage and control multiple DER facilities and other infrastructure (electric vehicle charging stations, load curtailment, etc.) including both company-owned and customer-owned facilities. DERMS will provide the information and control necessary to effectively manage the technical challenges posed by a more complex grid. The DERMS system provides the utility the ability to manage the impact of DER and operate the system more efficiently.

DERMS is an integral module of the ADMS that Unitil is implementing. After the initial ADMS deployment it is Unitil's intention to purchase and activate the DERMS license and integrate systems and data as needed for deployment. The Company has decided to include DERMS implementation within its ADMS project because of the integrated nature: DERMS is a module that is enabled within the ADMS system.

Unitil will require significantly more visibility and control of the DERs that will participate in the DERMS program including real-time invertor status, real and reactive power output, and voltage information. In the cases of energy storage Unitil will also need real-time information on available storage and dispatch control over the energy storage facility. It is Unitil's vision that these will be integrated via Unitil's SCADA/ADMS.

Initially Unitil plans to utilize DERMS to manage real and reactive power needs, but the system will have the capability to perform voltage management and be integrated into the VVO algorithm.

3.1.3.1.1 Description of Work Completed

In 2021, Unitil's completed the modelling and implementation of one substation (three circuits) in the ADMS production environment. In 2022, the Company completed the implementation of VVO of the same substation and three circuits in the production environment. ADMS/VVO when enabled is setting all regulator bandcenters and controlling all capacitor banks on the circuit to minimize losses and system demand. Formal on/off testing of this substation took place in 2023 and is expected to be completed in the first quarter of 2024.

The Company implemented unbalanced loadflow and began preliminary VVO testing on one additional substation (six circuits) in 2023. Formal on/off testing of this substation is expected to take place in 2024. The Company also enabled and configured the Switch Order module of ADMS in 2023. The Company plans to develop/modify workflows around the new Switch Order model and begin using is 2024.

Unitil is planning to implement unbalanced loadflow and VVO on one additional substation (two circuits) 2024. It also expected that the full initial (unbalanced loadflow, short circuit. Switch order module and VVO) deployment of the ADMS is expected to be completed by the end of 2024 with unbalanced loadflow, short circuit and VVO deployment on remaining substation and circuits following the VVO schedule.

In 2025 the Company plans to begin its DERMS implementation with the addition of the DERMS model to its ADMS platform. The Company plans to integrate the FG&E owned DER facilities for the testing of DERMS functionality. It is currently anticipated that DERMS will be available to customers in 2027.

3.1.3.1.2 Lessons Learned/Challenges and Successes

The majority of 2023 was spent configuring, troubleshooting and modifying the unbalanced load flow model for the new substation (six circuits) getting this functionality. This resulted in Unitil working closely with its ADMS vendor and ADMS integrator to test the performance of unbalanced loadflow and implement changes to resolve identified issues. Based on these efforts as well as the efforts implementing unbalanced loadflow on the initial substation, the Company now expects that the effort of implementing unbalanced loadflow for each substation will need to include an extensive testing and monitoring period prior to unbalanced loadflow being placed into "production" and for formal VVO on/off testing to commence.

3.1.3.1.3 Actual vs. Planned Implementation and Spending

The table below provides the actual versus planned implementation and spending. The 2022 Plan represents the projected spending in the 2022-2025 plan. The O&M cost estimates from 2023 – 2025 estimates an incremental full-time equivalent employee that will have the responsibility to provide ADMS oversight and analysis to ensure proper operation. The 2022 Actual includes the actual spending for 2022 and the updated projected spending for future years.

Year	2022		2023		2024	2025
	Plan	Actual	Plan	Actual	Plan	Plan
Capital Costs	$400,000	$58,783	$250,000	$103,435	$175,000	$125,000
O&M Costs	$174,000	$60,706	$176,000	$106,133	$177,000	$178,000
Total Costs	$574,000	$119,489	$426,000	$209,568	$352,000	$303,000

Table 13 – ADMS 2022-2023 Actual / 2024-2025 Forecast Spending

3.1.3.1.4 Performance on Implementation/Deployment

This project began in 2019. Unitil implemented an ADMS test system and modelled and implemented one unbalanced loadflow on one substation and three circuits in 2020. The implementation of the production system and the modelling of the initial substation and three circuits was completed in 2021. VVO implementation of the same substation and three circuits was completed in 2022. Implementation of unbalanced loadflow and VVO one additional substation and six circuits and the deployment of switch order module occurred in 2023. The remaining FG&E substations and circuits are expected to be fully modelled in ADMS by the end of 2024 with unbalanced loadflow and VVO following the VVO implementation schedule. DERMS implementation is expected to begin in late 2025 and is expected to take approximately two years to complete.

3.1.3.1.5 Description of Benefits Realized as the Result of Implementation

The ADMS will enable VVO and reduce customer energy consumption by 2% and is expected to reduce peak demand on the individual feeders and substations by similar amounts. This will directly benefit customers by reducing their electricity bills. The ADMS will also enable better voltage control for the integration of DER and improve reliability through the future implementation of FLISR.

3.1.3.1.6 Description of Capability Improvement

The Company ADMS system will be implemented with the following functionalities:

- GIS editor to transfer the network model from the GIS to the ADMS on a routine basis as changes to the network topology are made in GIS
- New process to provide ADMS customer load profile and generator output information.
- Verification of network connectivity
- Enhancements of the existing OMS
- Migration from the pre-existing standalone SCADA system to the ADMS SCADA system
- Switch Order Module (manager)and simulation module
- Manual Load Shed and System Power Factor Management
- Volt/VAr Optimization
- DERMS
- Crew assignments
- Engineering based load flow and circuit analysis tools
- Hardware, software, and training
- Hot standby fault recovery

3.1.3.1.7 Key Milestones

Below are some of the key milestones for the deployment of the Company's ADMS. The company is currently on schedule to meet these milestones.

- Q2 2024 – Summer Street VVO Begin Formal On/Off Testing
- Q3 2024 – Lunenburg Unbalanced Loadflow Implementation Complete
- Q3 2024 – Enhancements to Switch Order Module
- Q1 2025 – Lunenburg Begin Formal On/Off Testing
- Q4 2024 – Remaining FG&E Substation and Circuits Ready for Unbalanced Loadflow
- 2025 – West Townsend Unbalanced Loadflow Implementation Complete and Begin Formal On/Off Testing
- 2025 – Begin DERMS Implementation
- 2027 – DERMS Implementation Complete

3.1.3.1.8 Updated Projections for Remainder of the Three-year Term

Implementation began in 2020 with full integration of existing systems with all FG&E circuits being modelled in ADMS by the end of 2024. Additional VVO deployment utilizing ADMS will follow the VVO and SCADA schedules. DERMS implementation is expected to begin in 2025 and be available to customers in 2027.

At this time the Company is evaluating the possibility of expanding the scope of the ADMS project beyond 2025 to include additional functionality, such as FLISR or loss optimization if the benefits outweigh the cost of implementation. This added functionality would likely require the installation of additional fully automated field devices and sensors. Additionally, the Company plans to review the possibility of utilizing ADMS as the basis for advanced mapping, such as heat maps and hosting capacity maps, and engineering circuit analysis model development.

Additionally, in 2026 with the installation of a new AMI system the Company plans to evaluate "model-based" VVO to "meter-based" VVO. Meter-based VVO may provide the opportunity to deploy fewer line sensors as metering points while adding additional VVO functionality. The speed at which the AMI system is able to provide meter readings to the ADMS system will be a factor in the decision on transitioning to meter-based VVO.

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.

3.1.4.1 FIELD AREA NETWORK

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 is 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.

3.1.4.1.1 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.

3.1.4.1.2 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.

3.1.4.1.3 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 has updated its estimates and project plan to coincide with SCADA and the VVO projects.

	2022		2023		2024	2025
Year	Plan	Actual	Plan	Actual	Plan	Plan
Capital Costs	$198,000	$184,380	$0	$0	$0	$0
O&M Costs	$10,000	$26,328	$27,118	$26,650	$27,931	$28,769
Total Costs	$208,000	$210,708	$27,118	$26,650	$27,931	$28,769

Table 14 – FAN 2022-2023 Actual / 2024-2025 Forecast Spending

3.1.4.1.4 Performance on Implementation/Deployment

To date, the Company has installed and commissioned all network backbone infrastructure and 53 endpoint devices 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 tracked as part of the VVO project implementation.

3.1.4.1.5 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.

3.1.4.1.6 Description of Capability Improvement

In the context of the modern grid, communications is a foundational technology that makes it possible for systems, operators and stakeholders to interact and share information. The FAN will handle data traffic between distribution, grid edge devices, centralized information and operational systems. The FAN will be used by most of the modern grid systems to be implemented.

3.1.4.1.7 Key Milestones

Below are some of the key milestones for the deployment of the FAN. The Company is currently on schedule to meet these milestones.

- 2020-2022 FAN backbone infrastructure installed
- Cell Modems will be installed according to the VVO and SCADA implementations

3.1.4.1.8 Updated Projections for Remainder of the Three-year Term

Cell Modems will be installed according to the VVO and SCADA implementations.

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.

3.1.5.1 MOBILE PLATFORM DAMAGE ASSESSMENT

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.

3.1.5.1.1 Description of Work Completed

The Company has been researching and evaluating 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. The evaluation team includes 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 15 – Mobile Platform Damage Assessment Evaluation Criteria

After the initial review and evaluation, several vendors were invited into the Company to provide a presentation on their proposal so that the project team could a clearer understanding of their proposal and have 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 Mobile Information Management System (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. Efforts needed to complete the project including system and user acceptance testing, training and full implementation are expected to be completed in 2024.

3.1.5.1.2 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, or 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.

3.1.5.1.3 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	Plan
Capital Costs	$50,000	$25,048	$28,835	$101,096	$50,000	$50,000
O&M Costs	$50,000	$0	$16,000	$0	$16,000	$16,000
Total Costs	$100,000	$25,048	$44,835	$101,096	$16,000	$16,000

Table 16 – Mobile Platform Damage Assessment 2022-2023 Actual / 2024-2025 Forecast Spending

The costs shown in the table above include the estimated costs for the Company.

3.1.5.1.4 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 and final project completion estimated in 2024. Information on performance will be provided in the next annual report and as part of the Evaluation Plan.

3.1.5.1.5 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.

3.1.5.1.6 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

3.1.5.1.7 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 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.

3.1.5.1.8 Updated Projections for Remainder of the Three-year Term

The projections are shown in the table above. The increase in estimated costs associated with this project is related to 1) updated product costs between the original estimate and revised estimate; and 2) additional development time associated with integrations with existing systems.

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.

3.1.6.1 DER MITIGATIONS

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.

3.1.6.1.1 Description of Work Completed

The design and procurement stages started in 2022 for the first of these overvoltage protection improvement projects as part of the GMP (Canton Street substation), and in 2023 for the next two (Summer Street and Sawyer Passway substations). Implementation is expected to be completed in 2024 for all three of these.

3.1.6.1.2 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.

3.1.6.1.3 Actual versus Planned Implementation and Spending

The table below provides the planned implementation and spending for the remainder of this term of the GMP.

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

Table 17 – DER Mitigations 2022-2023 Actual / 2024-2025 Forecast Spending

3.1.6.1.4 Description of Benefits realized as the Result of Implementation

As the overvoltage protection improvement projects are completed at each substation, the risks of damage caused by ground-fault overvoltages on the 69 kV system due to DER on the distribution systems out of those substations will be decreased.

3.1.6.1.5 Key Milestones

Overvoltage protection improvements are planned to be completed for Sawyer Passway, Summer Street and Canton Street substations in 2024.

3.1.6.1.6 Updated Projection for Remainder of the Four-Year Term

Overvoltage protection improvements are planned to be completed for Sawyer Passway and Summer Street substations in 2023, and for Canton Street substation in 2024.

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 2023 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 distributed energy resources ("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 - DPU 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 18– 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 2023 was calculated at 297.3 customers per automated device. This equates to a 17.5% change. 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	2023 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	43
Total number of Circuits with Sensors	34	42
% of Substation/Transformers with Sensors	75.5%	97.7%

Table 19 – 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 is progressing with its GMP from an equipment and/or device standpoint.

4.2.1.1 Assumptions

The number of devices for each investment be determined and/or updated from the initial GMP. The number of devices installed will be 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 and the Company is in the process of developing detailed designs and detailed plans for each investment area. The Company will continue to update this as more detailed designs are completed.

4.2.1.2 Calculation Approach

The following information will be tracked and reported upon 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[4]	17	22	77%
OMS Integration with AMI[5]	0	1	0%
Volt/VAr Optimization			
VVO Capacitor Banks[6]	12	18	67%
VVO Voltage Regulators	31	57 [7]	42%
VVO LTCs[8]	2	3	67%
Monitoring[9]	65	84 [10]	77%
ADMS			
ADMS and DERMS	3	14	21%
DERMS	Under Review	Under Review	Under Review
Communications			
Field Area Network	0	Based upon VVO and SCADA Deployments	N/A
Workforce Management			
Mobile Platform Damage Assessment[11]	0	1	0%
DER Integration			
DER Mitigation	0	4	0%
AMI			

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

AMI Replacement	0	0	0%
Customer Engagement			
Customer Engagement and Experience	0	1	0%
Data Sharing	0	1	0%

Table 20 – Quantity of Devices by Investment

4.2.2 Lessons Learned/Challenges and Successes

The Company continues to make significant progress with respect to this performance metric. The recent supply chain challenges have extended lead times and delayed some projects. The Company is attempting to purchase equipment further in advance to adjust to the extended lead times.

4.2.3 ASSOCIATED COST FOR DEVELOPMENT

This metric measures the associated costs for the number of devices or technologies installed and is designed to measure how the Company is progressing.

4.2.3.1 Assumptions

The cost of devices or technologies for each investment will need to be determined and/or updated from the initial GMP. The cost of devices installed will be compared to the total cost of devices planned by circuit for each investment.

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

4.2.3.3 Results

The Total Cost of Devices Planned uses the costs incurred to date with estimated future costs. Where an updated estimate is not available, the amount in the GMP has been used.

Grid Modernization Investments	Cost of devices or other technologies deployed	Total cost of devices planned	Percent – Cost of devices installed / total cost of devices planned
Monitoring and Control			
SCADA	$1,209,472	$1,882,472	64%
OMS Integration with AMI	0	$129,900	0%
Volt/VAr Optimization			
VVO Capacitor Banks	$ 684,511	$ 703,800	97%
VVO Voltage Regulators	$ 1,240,534	$ 1,349,750	92%
VVO LTCs	$ 87,647	$ 178,762	49%
Monitoring	$ 718,216	$ 833,500	86%
Advanced Distribution Management System			
ADMS and DERMS	$496,935	$950,000	52%
Communications			
Field Area Network	$76,270	TBD	TBD
Workforce Management			
Mobile Platform Damage Assessment	$464,870	$650,000	0%
DER Integration			
DER Mitigation	$95,023	$958,240	10%
AMI			
AMI Replacement	$0	$11,253,379	0%
Customer Engagement			
Customer Engagement and Experience	$72,660	$1,212,000	6.0%
Data Sharing	$0	$544,000	0%

Table 21– Total Capital Costs of Devices Planned

4.2.4 Lessons Learned/Challenges and Successes

The Company continues to make significant progress with respect to this performance metric. The recent supply chain challenges have extended lead times and delayed some projects. The Company is attempting to purchase equipment further in advance to adjust to the extended lead times.

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

This metric is designed to measure how the Company is progressing under its GMP on a year-by-year basis.

4.2.5.1 Assumptions

The quantity and cost of devices or technology for each investment will need to be determined and/or 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 will be compared on a year-by-year basis and any variations will be quantified and addressed.

The Company notes that its GMP did not include a significant amount of detail and may need to be supplemented with detailed design and planning analysis to clarify the year-by-year construction plans.

4.2.5.2 Calculation Approach

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

a. Number of devices or technology installed versus plan for a given year
b. Cost of devices or technologies installed versus plan for a given year
c. Reason for discrepancies

4.2.5.3 Results

The primary drivers of the discrepancies in 2023 are the delay in implementation of the AMI replacement project, as described herein, and delay in material delivery for DER mitigation projects

4.2.6 Lessons Learned/Challenges and Successes

The Company continues to make significant progress with respect to this performance metric. The recent supply chain challenges have extended lead times and delayed some projects. The Company is attempting to purchase equipment further in advance to adjust to the extended lead times.

4.2.7 PROJECTED DEPLOYMENT FOR THE FOLLOWING YEAR

This metric is designed to measure how the Company is progressing under its GMP on a year-by-year basis. This will be used for the following year comparison of the plan versus the actual implementation completed in the following year.

4.2.7.1 Assumptions

The year-by-year investment plan is subject to change based upon the quantity of work completed, the availability of the technology, material lead times, contractor availability, etc. The revised investment plan each year will be used as the basis of comparison for the following year's GMP work.

4.2.7.2 Calculation Approach

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

a. Number of devices or technology to be installed the following year
b. Cost of devices or technologies installed the following year

4.2.7.3 Results

The table below identifies the expected spending for 2024. In some cases, where planned installation was not complete in the prior year(s) the number of devices listed includes those devices that were not complete previously and are expected to be complete in the following year. The cost of devices installed is the expected cost in the following year and does not include costs incurred in previous years for those devices.

Grid Modernization Investments	Number of devices or technology to be installed the following year	Cost of devices or technologies installed the following year
Monitoring and Control		
SCADA[12]	2	$640,000
OMS Integration with AMI	0	$0
Volt/VAr Optimization		
VVO Capacitor Banks	3	$ 17,703
VVO Voltage Regulators	17	$ 100,203
VVO LTCs	2	$ 60,000

[12] SCADA quantities listed here are the number of circuits with Grid Mod devices that include SCADA.

Monitoring	21	$ 105,580
Advanced Distribution Management System		
ADMS and DERMS	2	$50,000
Communications		
Field Area Network	n/a	$0
Workforce Management		
Mobile Platform Damage Assessment	1	$66,583
DER Integration		
DER Mitigation	4	$863,000
AMI		
AMI Replacement	7,700	$4,580,922
Customer Engagement		
Customer Engagement and Experience	0	$0
Data Sharing	0	$ 466,000

Table 22– Projected Deployment for 2024

4.2.8 Lessons Learned/Challenges and Successes

The Company is positioned to make significant progress with respect to this performance metric. The recent supply chain challenges have extended lead times and delayed some projects. The Company is attempting to purchase equipment further in advance to adjust to the extended lead times.

5 EVALUATION CONSULTANT RECOMMENDATIONS

In the D.P.U. 21-80/21-81/21-82 dated October 7, 2022, the Department requires 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 Department acknowledges that the Companies consider the recommendations from the 2018-2021 term in their plan development and implementation, and that not all recommendations may be feasible. (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.

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 it 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.

5.2 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 will continue 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 will continue 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 will continue 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 will continue to work with Guidehouse on identifying case studies.

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

The Company will continue 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.

5.3 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 accepts this recommendation and will implement 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 accepts 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 will continue to work with Guidehouse to fine tune VVO M&V.

5.3.6.3 Implementation Status of Recommendation

The Company accepts this recommendation and will continue 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 accepts this recommendation and will implement 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 accepts this recommendation and will implement 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 accepts this recommendation and will implement 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 is working 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 is working with Guidehouse on this recommendation.

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 is evaluating the ability to practically implement this recommendation.

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 accepts 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 accepts this recommendation and strives to meet the on/off schedule.

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 accepts 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 accepts this recommendation and is currently working 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 accepts 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 accepts 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 will continue 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 will continue 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 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 identifies this information as a variation from the previously approved AMI project in the 2022-2025 plan. As such, The Company has filed a petition with the Department (DPU 24-54) to revise the scope of the original AMI project and obtain preauthorization of these AMI investments. 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 2023, the Company evaluated four vendor proposals for the replacement of the existing AMI system. This process consisted of identifying several key functional areas including Metering, Billing, Engineering, Operations, and IT/Cyber Security and assigned a team of subject matter experts to participate in the vendor proposal technical evaluation process. The Company received four proposals for the AMI system and three proposals for the meter exchange process. The Company held virtual meetings with each vendor to discuss their proposals and address technical questions, and completed an initial technical evaluation consisting of scoring based on the RFP requirements and overall system functionality. Unitil also hosted focused demonstrations with three of the vendors to demonstrate specific use case scenarios, user interfaces, and integrations with other systems. This process resulted in the selection of two finalists, which were invited on-site to demonstrate a "Proof-of-Concept" test of their respective systems. Ultimately, Landis+Gyr was selected as the AMI system vendor and Utility Partners of America was selected as the meter exchange vendor.

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 has presented the Company with both challenges and opportunities. The major challenges are associated with budgetary and resource constraints associated with implementing a project of this magnitude in the time required. However, 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 Company did not originally plan to replace its AMI infrastructure as part of its Grid Modernization plan.

	2022		2023		2024	2025
Year	Plan	Actual	Plan	Actual	Plan	Plan
Capital Costs	$2,346,000	$76,270	$0	$0	$4,580,922	$6,672,457
O&M Costs	$0	$0	$0	$0	$0	$132,081
Total Costs	$2,346,000	$0	$0	$0	$4,580,922	$6,804,538

Table 23 – AMI 2023 Actual / 2024-2025 Forecast Spending

6.1.4 Performance on Implementation/Deployment

The deployment of the AMI system is planned to begin in 2024.

6.1.5 Description of Benefits realized as the Result of Implementation

The Company did not complete the implementation in 2023.

6.1.6 Key Milestones

Milestones for the AMI Deployment are:

- Vendor Contract Signing: May 2024
- Technical Workshops: June-July 2024

- HES Build & Test: Q2-Q3 2024
- FAN Network Deployment: Q2-Q4 2024
- Meter Exchange: Q4 2024 – Q4 2025

6.1.7 Updated Projection for Remainder of the Four-Year Term

The Company intends to standup the software HES and perform all system integration testing in 2024. In parallel, the Company also plans to install and commission the communications network. Upon completion of this work, the meter replacement will immediately follow and is scheduled to start in late 2024 with the majority of replacements being completed in 2025.

6.2 CUSTOMER ENGAGEMENT AND EXPERIENCE

The Company has developed a roadmap that is aimed to best meet the needs of the customers to meet their objectives of reducing their bill amount, their usage, or their carbon footprint. The initiatives and technologies outlined in the plan are designed to support the customers' experience and their satisfaction in all facets of that experience. This project will strengthen current service offerings, make enhancements to our customer web portal and add self-service options that enable customers to better manage their energy usage and accounts. These planned enhancements include a mobile app, artificial intelligence and chat features, and a robust notification engine to proactively alert customers regarding payment activity, changes in usage patterns, outages, and scheduled appointments.

6.2.1 Description of Work Completed

<u>Work completed in 2023:</u>

- <u>Apogee Rate Comparison Tool:</u> The Company contracted with Apogee, conducted functional and integration testing and deployed the tool in our New Hampshire subsidiary. This tool is a rate-comparison calculator that integrates with billing history and AMI data and computes the customer's monthly and annual energy costs, which allows them to choose the rate plan most suited to their homes, flexibility, and lifestyles. Additionally, this tool is an EV Calculator which allows customers to utilize multiple sliders with EV information and personal driving variabilities to assist customers to understand how an EV time varying rate may benefit their purchase of an electric vehicle. This tool has been made available to FG&E's customers in conjunction with the deployment of the EV TOU rates.
- <u>Customer Experience Management Solution:</u> The Company contracted with Systems & Software and began functional testing of the solution in 2022. This system is an integrated web portal that will add self-service options enabling customers to better manage their energy usage and account information. The solution additionally will include a mobile app, artificial intelligence and chat features, coupled together with a robust notification engine to proactively alert customers regarding payment activity, increases in usage, outage notifications, and the status of scheduled appointments – all of which will provide a responsive integrated web experience for our customers.
- <u>Utility Bill Redesign:</u> The Company conducted thorough functional and integration testing in 2022 for this project that transitions our bill from a system generated bill using set designs on pre-printed billing forms to

a dynamic bill print job. Personalizing messaging by customer class, location and interests in products and services can all be attained through a more dynamic billing product. This change will utilize color, different fonts, graphs and other tools will allow the Company to draw attention to key information serving as valuable educational opportunities for various new products and services, rate plans, and behind the meter partnerships.

6.2.2 Lessons Learned/Challenges and Successes

The Company learned that one vendor was unable to provide all of the customer needs as outlined in the customer experience roadmap. Rather, we determined that multiple vendors are needed to provide rate comparison tools separate from some of the other tools included in the customer experience management solution. Additionally, the Company is in the process of a significant CIS upgrade project and realized that the customer experience management solution could not be made available to customers until that upgrade was completed. While this complicated the deployment of some of the customer facing solutions, both the CIS upgrade and the customer experience management solution will be deployed simultaneously because the same vendor is responsible for both systems.

6.2.3 Actual Versus Planned Implementation and Spending

The following table demonstrates the project plan (including 2022 actuals) to implement the functionality associated with the Customer Engagement and Experience project:

Description	2022		2023		2024	2025	2026 - 2030
	Plan	Actual	Plan	Actual	Plan	Plan	Plan
Customer Experience Mapping/Impleme ntation	$186,000	$16,922	$75,000	$0	$0	$0	$0
Customer Engagement Marketplace					$0	$566,000	
Artificial Intelligence Solution/Personaliz ed Selling							
Utility Bill Redesign	$55,000	$14,316	$16,000	$9,120			
Work Order Job Scheduler (BTM Partner Work)						$0	$109,000
Customer Engagement and Experience Total	$241,000	$31,238	$91,000	$9,120	$0	$566.000	$109,000

Table 24 - Customer Engagement and Experience Project Plan

This table represents the Company's allocation of the overall project. The remainder of the project will be funded by other Unitil Corporation subsidiaries. The following table provides a summary of spending for the short-term investment plan. 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 Plan	2022 Actual	2023 Plan	2023 Actual	2024	2025	2026 - 2030
Capital Costs	$241,000	$31,238	$91,000	$9,120		$566,000	$109,000
O&M Costs	$0	$16,151	$16,151	$16,151	$16,151	$66,000	$366,000
Total Costs	$241,000	$47,389	$107,151	$25,271	$16,151	$632,000	$475,000

Table 25 - Customer Engagement and Experience 2022-2023 Actual / 2024-2025 Forecast Spending

6.2.4 Performance on Implementation/Deployment

The Company completed the Utility Bill Redesign portion of the project. To date the project has met the expected outcome.

6.2.5 Description of Benefits realized as the Result of Implementation

The Company and its customers have not yet been able to realize the benefit of the implementation but the Company performed much of the setup work needed to prepare for live deployments.

6.2.6 Key Milestones

Key Milestones for the Customer Experience Initiatives:

- Apogee Rate Comparison Tool: April, 2023
- Customer Experience Management Solution: March, 2024
- Utility Bill Redesign: April, 2023
- Customer Engagement Marketplace and AI: 2025
- Work Order Job Scheduler: 2025

6.2.7 Updated Projection for Remainder of the Four-Year Term

Key Milestones for the Customer Experience Initiatives:

- Apogee Rate Comparison Tool: April, 2023
- Customer Experience Management Solution: March, 2024
- Utility Bill Redesign: April, 2023
- Customer Engagement Marketplace and AI: 2025

- Work Order Job Scheduler: 2025

6.3 DATA SHARING PLATFORM

Unitil Corporation subsidiary, Unitil Energy Systems (UES) located in New Hampshire ("NH") has filed a proposed approach for data sharing in NH PUC Docket No. DE 19-197. Unitil Service Corporation has taken a lead on developing a proposal for a data sharing platform and if found to be successful, Unitil Service Corporation would provide the data sharing platform to the Company as well.

In March of 2022, the 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. The data platform will enable customers, as well as third-party energy providers, to access energy consumption data from all regulated electric and natural gas utilities through a single secure portal.

6.3.1 Description of Work Completed

Market demand and the regulatory environment will dictate the implementation cadence of this capability. Unitil is keenly aware of this and is taking a measured approach focusing initially on foundational technologies and building stakeholder consensus on definition of the necessary functional capabilities and the prioritization of those requirements.

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 later this calendar year. This industry standard technology will form the backbone for Unitil's data sharing strategy and serve as the company's primary interface to the planned NH Data Sharing Platform.

6.3.2 Lessons Learned/Challenges and Successes

Soliciting stakeholder input and consensus collaboration have been a challenging endeavor in our New Hampshire affiliates. It is possible that similar challenges will exist in Massachusetts and that this may impact schedule.
The Company will have unique challenges associated with the process of mining and combining customer energy data from individual, disparate systems to the platform. Numerous technical and non-technical hurdles exist with retrieving and processing the data necessary to support the platform. For example, these data may exist in various vendor relational database systems, they may exist in flat or unstructured data files, or even in legacy mainframe systems. All of these scenarios will require the data extraction and parsing systems (the "extract" portion of the traditional ETL, or extract, transform and load model), representing a complex and non-trivial exercise.
After the Company has completed all of the work necessary to identify and extract the required data from internal systems, a second challenge unique to each company arises: combining all of the data as the result of these

"extraction" efforts into a single, cohesive, data set that can be interpreted and processed by third-parties (the "transform" portion of the ETL model). Without complex standardization and coordination across the utilities, this would be a near impossibility. The introduction of a "Logical Data Model" attempts to solve some of these problems.

The model provides a common abstraction with agreed upon semantics for field names and data conventions, allowing the utilities to "speak the same language" with common terms and agreed upon units of measurement. The Energy Service Provider Interface (ESPI) data standard released and maintained by the North American Energy Standards Board (NAESB) is proposed to be used as the basis for the model. If data fields are required that are above and beyond what is offered in the ESPI model, the desired approach is to work with the governing body to extend the model, however the standard is already quite robust containing constructs for various energy usage components such as: Usage Points, Meter Readings, Intervals, Reading Types, etc.

The proposed Logical Data Model will act as a "mapping layer" that sits on top of the native utility data sets. Because of this mapping layer, changes are not required to their existing back end systems to support this. However, it would still require a non-trivial data mapping exercise. Adherence to this logical data standard is a cornerstone of the "Virtual Energy Data Platform" as this is what allows multi-utility data to be combined by the API consumer.

6.3.3 Actual versus Planned Implementation and Spending

Year	2022 Plan	2022 Actual	2023 Plan	2023 Actual	2024	2025
Capital Costs	$466,000	$0	$0	$0	$466,000	$78,000
O&M Costs	$ 0	$0	$0	$0	$0	$0
Total Costs	$466,000	$0	$0	$0	$466,000	$78,000

Table 26 - Data Sharing 2022-2023 Actual / 2024-2025 Forecast Spending

6.3.4 Performance on Implementation/Deployment

This project was not approved until November 2022. Therefore, deployment has not started. Based upon the delayed approval and the stakeholder engagement process, it is expected this project will occur in 2024 and 2025.

6.3.5 Description of Benefits realized as the Result of Implementation

There is a consistent trend with the data offerings that raises questions as to the value of investing in a data platform. Today, customers may download, and otherwise use their energy usage data for a variety of reasons. But to date, very few customers have leveraged these options. This project seeks to enable expanded uses for energy usage data designed for additional user types. The Company believe the limited engagement with current data service offerings should be considered when deciding the size and scope of a data platform. Alternatively, the Company understand that automating the transfer of energy data might spur more use. The actual use of customer energy data will of course be taken into consideration in the benefits when determining the cost effectiveness of implementing any solution. If the platform is utilized, it should be because the benefits of such a platform are clearly-defined and demonstrated to provide meaningful value to a sizeable number of customers.

This project will have the following benefits to our customers:

- enable customers to better manage their energy consumption
- lower monthly electric bills
- benefit from new products and services offered
- lower transmission capacity costs
- deferred spending on capacity improvements
- lower GHG emissions
- data to support community aggregation
- DER providers can gain access to a larger consumer market

6.3.6 Key Milestones

The Company continues to make progress towards implementing foundational technical and process building blocks that will help to enable our data sharing goals. The planning, governance and design discussions in New Hampshire that Unitil has taken a leadership role in, as well as the updates to our CIS platform with Green Button Connect My Data capabilities coming in 2024, position us well for success with these efforts in Massachusetts in the years to come. Unitil recently completed efforts to develop and submit a proposal for federal funding through the US Department of Energy's Grid Resilience and Innovation Partnership (GRIP) Grant program. If awarded, these funds will be used both to buy down the cost of the NH Data Sharing Platform as well as to fund the expansion of the platform to neighboring states while providing additional functionality in support of underserved communities.

6.3.7 Updated Projection for Remainder of the Four-Year Term

This project was not approved until November 2022. Therefore, deployment has not started. Based upon the delayed approval and the stakeholder engagement process, it is expected this project will occur in 2024 and 2025.

7 CONCLUSION

Overall, the Company is making significant progress towards the design and implementation of its Grid Modernization plan. 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. The Company's efforts over the past year have focused on implementation. The Company's analysis and design work has identified efficiencies such as combining VVO functionality with the ADMS and adjusting the schedule to align the FAN, VVO, ADMS and SCADA projects. A considerable amount of effort has been expended even though these efforts are not easily quantified with number of units installed or amount of money spent.

The Company continues to experience supply chain challenges with respect to COVID-19 which affected material lead times and project implementation schedules. The Company is attempting to purchase equipment further in advance to help with implementation schedules.

The Company continues to take a measured approach to implementation, working to control costs and use internal resources as much as possible. The Company has developed a project management structure that will ensure grid modernization is implemented in an efficient manner.

Appendix 1

DPU Appendix 1 Template

NOTE:

DPU APPENDIX 1 TEMPLATE PROVIDED IN ELECTRONIC FORMAT ONLY

Appendix 2

System Automation Saturation

2023 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	620	0	0	0	0	0	0	1	0	0	0	1	620.0
Beech Street	1W2	1,995	0	1	0	0	0	1	1	0	0	0	1	1,330.0
Beech Street	1W4	1,660	0	1	0	0	0	1	1	0	0	0	1	1,106.7
Beech Street	1W6	1	0	0	0	0	0	0	1	0	0	0	1	1.0
Beech Street		**4,276**	**0**	**2**	**0**	**0**	**0**	**2**	**4**	**0**	**0**	**0**	**4**	855.2
Canton Street	11H10	756	0	0	0	0	0	0	0	0	0	0	0	---
Canton Street	11H11	374	0	0	0	0	0	0	0	0	0	0	0	---
Canton Street	11W11	1,778	0	0	0	0	0	0	0	0	0	0	0	---
Canton Street		**2,908**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	---
Townsend	15W14	0	0	0	0	0	0	0	1	1	0	0	2	0.0
Townsend	15W15	1	0	0	0	0	0	0	1	0	0	0	1	1.0
Townsend	15W16	1,535	0	0	0	0	9	9	1	0	0	0	1	279.1
Townsend	15W17	574	0	0	0	0	1	1	1	0	0	0	1	382.7
Townsend		**2,110**	**0**	**0**	**0**	**0**	**10**	**10**	**4**	**1**	**0**	**0**	**5**	211.0
Nockege	20W22	896	0	0	0	0	0	0	1	0	0	0	1	896.0
Nockege		**896**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**0**	**1**	896.0
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	2,112	0	0	0	0	0	0	1	0	0	0	1	2,112.0
Sawyer Passway	22W2	155	0	0	0	0	0	0	1	0	0	0	1	155.3
Sawyer Passway	22W3	20	0	0	0	0	0	0	1	0	0	0	1	20.0
Sawyer Passway	22W8	155	0	0	0	0	0	0	1	0	0	0	1	155.3
Sawyer Passway	22W10	0	0	0	0	0	0	0	1	0	0	0	1	0.0
Sawyer Passway	22W11	155	0	0	0	0	0	0	1	0	0	0	1	155.3
Sawyer Passway	22W12	0	0	0	0	0	0	0	1	0	0	0	1	0.0
Sawyer Passway	22W17	0	0	0	0	0	0	0	1	0	0	0	1	0.0
Sawyer Passway		**2,598**	**0**	**0**	**0**	**0**	**0**	**0**	**8**	**0**	**0**	**0**	**8**	324.8
River Street	25W27	1,237	0	0	0	0	0	0	1	0	0	0	1	1,237.0
River Street	25W28	639	0	0	0	0	0	0	1	0	0	0	1	639.0
River Street	25W29	6	0	0	0	0	0	0	1	0	0	0	1	6.0
River Street		**1,882**	**0**	**0**	**0**	**0**	**0**	**0**	**3**	**0**	**0**	**0**	**3**	627.3
Lunenburg	30W30	1,409	0	0	0	0	14	14	1	4.5	0	0	5.5	112.7
Lunenburg	30W31	1,700	0	1	0	0	15	16	1	4	0	0	5	130.8
Lunenburg		**3,109**	**0**	**1**	**0**	**0**	**29**	**30**	**2**	**8.5**	**0**	**0**	**10.5**	121.9
Pleasant Street	31W34	1,274	0	0	0	0	0	0	1	0	0	0	1	1,274.0
Pleasant Street	31W37	1,253	0	0.5	0	0	0	0.5	1	7.5	0	0	8.5	143.2
Pleasant Street	31W38	1,291	0	0	0	0	0	0	1	3	0	0	4	322.8
Pleasant Street		**3,818**	**0**	**0.5**	**0**	**0**	**0**	**0.5**	**3**	**10.5**	**0**	**0**	**13.5**	277.7
Rindge Road	35W36	806	0	0	0	0	0	0	1	3	0	0	4	201.5
Rindge Road		**806**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**3**	**0**	**0**	**4**	201.5

2023 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
West Townsend	39W18	1,980	0	0	0	0	0	0	1	4	0	0	5	396.0
West Townsend	39W19	1,337	0	1	0	0	0	1	1	1	0	0	2	534.8
West Townsend		**3,317**	**0**	**1**	**0**	**0**	**0**	**1**	**2**	**5**	**0**	**0**	**7**	**442.3**
Summer Street	40W38	49	0	0	0	0	0	0	1	0	0	0	1	49.0
Summer Street	40W39	404	0	0	0	0	1	1	1	1	0	0	2	161.6
Summer Street	40W40	1,593	0	2.5	0	0	11	13.5	1	1	0	0	2	182.1
Summer Street	40W42	1,855	0	0	0	0	4	4	1	1	0	0	2	463.8
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		**3,901**	**0**	**2.5**	**0**	**0**	**16**	**18.5**	**6**	**3**	**0**	**0**	**9**	**213.8**
Princeton Road	50W51	660	0	0	0	0	0	0	1	0	0	0	1	660.0
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	194	0	0	0	0	0	0	1	0	0	0	1	194.0
Princeton Road	50W56	151	0	0	0	0	0	0	1	0	0	0	1	151.0
Princeton Road		**1,006**	**0**	**0**	**0**	**0**	**0**	**0**	**5**	**0**	**0**	**0**	**5**	**201.2**
	Total Customers	**30,627**					**Total Partially Automated Devices**	**62**				**Total Fully Automated Devices**	**72**	**297.3**

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

2023 EOY

		Number of Sensors By Type										
Substation	Circuit	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	11H10	0	0	0	0	0	0	0	0	0	1	1
Canton Street	11H11	0	0	0	0	0	0	0	0	0	1	1
Canton Street	11W11	0	0	0	0	0	0	0	0	0	0	0
Canton Street		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**2**	**2**
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	4	23
Townsend	15W17	1	0	0	0	0	0	1	3	0	2	7
Townsend		**4**	**1**	**0**	**0**	**0**	**0**	**10**	**12**	**0**	**6**	**33**
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	0	0	0	0	0	0	0	0	1	2
River Street	25W29	1	0	0	0	0	0	0	0	0	0	1
River Street		**3**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**5**	**8**
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	7.5	0	0	0	0	0	0	0	0	8.5
Pleasant Street	31W38	1	3	0	0	0	0	0	0	0	0	4
Pleasant Street		**3**	**10.5**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**3**	**16.5**
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**

2023 EOY

		Number of Sensors By Type										
Substation	Circuit	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
West Townsend	39W18	1	4	0	0	0	0	0	0	0	2	7
West Townsend	39W19	1	1	0	0	0	0	0	0	0	2	4
West Townsend		**2**	**5**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**4**	**11**
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	3	7
Summer Street	40W40	1	2	0	0	0	0	11	8	0	4	26
Summer Street	40W42	1	1	0	0	0	0	4	2	0	0	8
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**	**7**	**44**
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	0	0	0	0	0	0	0	0	0	1
Princeton Road		**5**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**6**

Total number of Substations	13
Total number of Substations with Sensors	13
% of Substation with Sensors	100.0%
Total number of Circuits	43
Total number of Circuits with Sensors	42
% of Circuits with Sensors	97.7%

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.