Electric Sector Modernization Plan

January 2024

Unitil

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Acronyms

Abbreviation	Description
AC	Alternating Current
ACEEE	American Council for an Energy-Efficient Economy
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
API	Application Programming Interface
BEA	Bureau of Economic Analysis
BTM	Behind the Meter
BTU	British Thermal Unit
C&I	Commercial and Industrial
CECP	Massachusetts Clean Energy and Climate Plan
CESAG	Community Engagement Stakeholder Advisory Group
CIS	Customer Information System
CMI	Customer Minutes of Interruption
CPP	Critical Peak Pricing
DA	Distribution Automation
DEI	Diversity, Equity and Inclusion
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DPU	Department of Public Utilities
DTH	Dekatherm
EDC	Electric Distribution Company
EE	Energy Efficiency
EEI	Edison Electric Institute
EFSB	Energy Facilities Siting Board
EJ	Environmental Justice
EJC	Environmental Justice Community
ERP	Emergency Response Plan
ESMP	Electric System Modernization Plan
ESS	Energy Storage System
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FAN	Field Area Network
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation, and Service Restoration
FTM	Front of the Meter
GHG	Greenhouse Gas Emissions
GIS	Geographic Information System
GMAC	Grid Modernization Advisory Council
GPS	Global Positioning System
GMP	Grid Modernization Plan
HVAC	Heating, Ventilation and Air Conditioning

IVM	Integrated Vegetation Management
ISO-NE	Independent System Operator – New England
IVR	Integrated Voice Recognition
kV	kilovolt (1,000 Volts)
kW	kilowatt (1,000 Watts)
LTC	Load Tap Changer
MA-DOT	Massachusetts Department of Transportation
MW	Megawatt (1,000,000 Watts)
N-1	Planning term used signify the removal of one element from the analysis
NWA	Non-Wire Alternatives
OMS	Outage Management System
PLC	Power Line Carrier
PLX	Gridstream PLX Technology
PPC	Poor Performing Circuit
PV	Photovoltaic
RIMS II	Regional Input-Output Modeling System
RCP	Representative Concentration Pathways
RFP	Request for Proposal
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SER	System Event Review
SMG	Senior Management Group
SPC	Strategic Planning Committee
SQ. FT.	Square Feet
SRP	Storm Resiliency Program
TOU	Time of Use
VAr	Volt Ampere Reactive
VPP	Virtual Power Plant
VVO	Volt VAr Optimization
UBLF	Unbalanced Load Flow
W	Watt
WTHI	Weighted Temperature-Humidity Index

Definitions

Term	Definition
Advanced Distribution Management System (ADMS)	ADMS is a computer system that provides system operators with an as-operated electrical model of the entire distribution system and support advanced applications for fault location, automated restoration and voltage management.
Advanced Metering Infrastructure (AMI)	AMI refers to a modern system of utility meters, sometimes referred to as "smart meters". AMI uses advanced technology, such as two-way digital communication, to collect and transmit data. A key added value of AMI is the ability to remotely collect data, control the meter, or check the service status during an outage event.
Behind the Meter (BTM)	BTM refers to DER installations located on the customer side of the electric meter. It typically involves rooftop solar panels, residential energy storage systems, demand response and other DERs that are installed at individual homes or businesses.
Blue-sky	Days without storms.
Breaker	A circuit breaker is a device designed to provide protection to the circuit during an abnormal condition. The breaker automatically breaks current when it detects fault conditions such as overcurrent or short circuit.
Bridge to Wires	Bridge to Wires refers to the use of DER (technology agnostic and likely third-party owned), dispatched by Unitil's system operators, to add operational flexibility in areas with growing demand where traditional solutions are required.
Capacity	The rated and continuous load-carrying ability, expressed in megawatts or megavolt-amperes, of generation, transmission, or other electrical equipment
Capital Investment Project (CIP)	CIPs are projects aimed at facilitating the deployment and interconnection of distributed generation as outlined by D.P.U. order 20-75B of November 24, 2021.
Clean Energy and Climate Plan (CECP)	The 2022 "Clean Energy and Climate Plan for 2025 and 2030" and "Clean Energy Climate Plan for 2050" aim to achieve emissions reduction for the Commonwealth set by the Climate Act (see below). The Secretary of EEA has adopted the interim 2025 statewide greenhouse gas emissions limit of 33 percent below 1990 level and the interim 2030 statewide greenhouse gas emissions limit of 50 percent below 1990 level. Clean Energy and Climate Plan for 2025 and 2030: https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030

	Clean Energy and Climate Plan for 2050: https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050#development-of-the-clean-energy-and-climate-plan-for-2050-
Climate Act (or the Act)	The 2021 "Act Creating a Next-Generation Roadmap For Massachusetts Climate Policy" set the target of net zero statewide greenhouse gas emissions by 2050. In addition, the Act defines Environmental Justice Populations and "environmental burden" in state statutes.
Community Benefits Agreement (CBA)	The purpose of Community Benefits Agreements is to ensure that communities that host clean energy infrastructures directly benefit from those infrastructures.
Community Engagement Stakeholder Advisory Group (CESAG)	Proposed by the EDCs, the goal of the CESAG is to develop a Community Engagement Framework that can be integrated when implementing new clean energy infrastructure projects.
Community Solar	Community Solar refers currently to solar generation facilities that provide electricity or bill credits to multiple utility customers. In addition, Eversource is proposing the Community Solar Access Program (ECSAP) and the Affordable Solar Access Program (ASAP) which are under DPU review.
Customer Average Interruption Duration Index (CAIDI)	Customer Average Interruption Duration Index (CAIDI) represents the average time required to restore service. CAIDI in typically measured in minutes.
Demand Response (DR)	DR includes any load that is flexible in its consumption and can, through external triggers or incentives, be made to change its behavior. This can include traditional DR solutions such as heating and cooling, or up and coming solutions such as Charge Management.
Distributed Energy Resource (DER)	DERs include a wide variety of distributed generation (DG) resources, energy storage systems (ESS), or flexible load commonly referred to as demand response (DR) that are controllable and connected to the distribution system.
Distributed Energy Resource Management System (DERMS)	Control room tool to manage, monitor, and dispatch DER based on real time system conditions. DERMS is a foundational platform capability intended to increase the efficiency and effectiveness of DER integration and to enable the use of DER as a grid asset.
Distributed Generation (DG)	DG includes a wide variety of generation resources connected to the distribution system that either export to the distribution system or are intended for behind the meter self-consumption. They include both conventional generation resources such as CHP, Diesel, Gas Turbines, or other form of generators, as well as renewable generation resources such as solar and wind.
Distribution	The delivery of electricity to end users via low-voltage electric power lines.

Electric Distribution Companies (EDC)	EDCs refer to the Massachusetts electric distribution companies: Fitchburg Gas and Electric Light Company d/b/a/ Unitil, NSTAR Electric Company d/b/a/ Eversource, and Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid.
Energy Efficiency (EE)	EE represents programs that have created a permanent, non-dispatchable load reduction through improvement to building systems, structures, or operations.
Energy Storage System (ESS)	ESS includes any technology that can store energy for any amount of time and discharging that energy as electric power. ESS can include chemical storage systems such as lithium-ion systems or other modes of storage, such as pumped hydro.
Environmental Benefits	Based on current state law, Environmental Benefits means the access to clean natural resources, including air, water resources, open space, constructed playgrounds and other outdoor recreational facilities and venues, clean renewable energy course, environmental enforcement, training and funding disbursed or administered by EEA.
Environmental Justice (EJ)	From current state law, Environmental Justice is based on the principle that all people have a right to be protected from environmental hazards and to live in and enjoy a clean and healthful environment regardless of race, color, national origin, income, or English language proficiency. Environmental justice is the equal protection and meaningful involvement of all people and communities with respect to the development, implementation, and enforcement of energy, climate change, and environmental laws, regulations, and policies and the equitable distribution of energy and environmental benefits and burdens.
Environmental Justice Community (EJC)	See Environmental Justice Population.
Environmental Justice Population	Based on current state law, an Environmental Justice Population is a neighborhood that meets one or more of the following criteria: (i) the annual median household income is not more than 65% of the statewide annual median household income; (ii) minorities comprise 40% or more of the population; (iii) 25% or more of households lack English language proficiency; or (iv) minorities comprise 25% or more of the population and the annual median household income of the municipality in which the neighborhood is located does not exceed 150% of the statewide annual median household income.
Equity	Equity means engaging all stakeholders – including our customers and communities – with respect and dignity while working toward fair and just outcomes, especially for those burdened with economic challenges, racial inequity, negative environmental impacts and justice disparities. ○ **Procedural Equity:** focuses on creating transparent, inclusive, and accessible processes for engagement, such that stakeholders and communities impacted by energy projects and programs are given

	necessary information and opportunity to participate in processes to inform project siting, development, and implementation ○ **Distributional Equity:** focuses on enabling a more equitable distribution of the benefits and burdens associated with the clean energy transition. ○ **Structural Equity:** focuses on developing processes and decisions that are informed by the historical, cultural, and institutional dynamics and structures that have led to inequities.
Feeder	Feeders are electrical circuits emanating from a substation that supply underground areas at distribution level voltages. Feeders do not supply customer level transformers directly except for underground network areas.
FERC Order 2222	The Federal Energy Regulatory Commission (FERC) issued Order No. 2222 in 2020, with updates in 2021. The main goal of Order No. 2222 is to better enable distributed energy resources (DERs) to participate in the electricity markets run by regional grid operators.
Flexible Interconnections	Flexible Interconnections allow DER to interconnect to the distribution system with agreed upon operating constraints that reduce the need for system modifications.
Forward Capacity Market (FCM)	The FCM is a locational capacity market managed by ISO-NE. In this market, ISO-NE projects the needs of the power system three years in advance and then holds an annual auction to purchase power resources to satisfy the region's future needs.
Front of the Meter (FTM)	Front of the Meter, usually refers to activities, technologies, or systems that are located on the utility side of the electricity meter. For this ESMP, it typically refers to utility-scale ESS.
Generation	The production of electric energy.
Geographic Information System (GIS)	The GIS system is the as-built asset repository which is the primary source model of the distribution system. The GIS asset and connectivity model serves as the source system for real time operations, and system planning models.
Grid Services Solution	Dispatch of customer owned and aggregated BTM and third-party FTM DER to manage system constraints in real time to cost effectively address local capacity constraints or better optimize voltage levels.
Headroom	Headroom refers to the margin of available capacity at a specific equipment to accommodate additional load without causing violations of equipment specifications.
Heat Pump Air-Source Heat Pump (ASHP)	A heat pump is a device capable of heating and cooling a building. During the heating mode, a heat pump extracts heat from an external source (air or ground) and transfers it into the home. In the cooling mode, the process is reversed, and heat is taken from indoor air and expelled outside.

Ground-Source Heat Pump (GSHP)	
Hosting Capacity	Hosting capacity is the estimated maximum amount of energy from a distributed resource (such as solar panels) that can be accommodated on the distribution system at a given location. This capacity is under existing grid conditions and operations without requiring significant infrastructure upgrades. This capacity takes into consideration safety, power quality, reliability, or other operational criteria.
Interconnection	The connection of DERs to the power grid that ensures safe operations in all grid conditions.
Inverter	An inverter is a device that converts direct current (DC) electricity, which is what a solar panel generates or energy storage system discharges, to alternating current (AC) electricity, which the electrical grid uses to serve load.
Load	The demand for electricity; electricity consumption; the amount of electric power delivered to any specified point on a system, accounting for the requirements of the customer's electrical equipment.
Meaningful Involvement	Based on current state law, Meaningful Involvement means that all neighborhoods have the right and opportunity to participate in energy, climate change, and environmental decision-making including needs assessment, planning, implementation, compliance and enforcement, and evaluation, and neighborhoods are enabled and administratively assisted to participate fully through education and training, and are given transparency/accountability by government with regard to community input, and encouraged to develop environmental, energy, and climate change stewardship.
Non-Traditional Solution	Alternative approaches to meeting system need. These solutions are Company owned and operated non-traditional approaches compared to the traditional system upgrade solutions.
Non-Wires Alternative (NWA)	NWAs are technologies or operating practices intended to reduce grid congestion and manage peak demand to offset a utility's need to make additional investments in conventional assets like wires, poles, and substations. The technologies can include distributed energy resources, such as microgrids or batteries, and practices and programs focused on load management, demand response or energy efficiency.

Outage Management System (OMS)	The OMS is a detailed network model of the distribution system based on Unitil's GIS. By combining the locations of outage calls from customers, a rules engine is used to predict the locations of outages. OMS data is also used to provide customers with detailed information regarding their outage.
Peak Load	Peak load refers to the highest electricity demand experienced by the grid during a specific period.
Peak Shaving	Peak shaving refers to a strategy to reduce or "shave" the peak electricity demand during periods of highest usage.
Recloser	Reclosers are pole-mounted distribution line equipment which automatically respond to faults by opening to isolate the sections of circuits that are damaged.
Reliability	The assurance that electric power is available even under adverse conditions, such as storms or outages of generation or transmission lines.
Resiliency	Resiliency is the ability of the grid to withstand and rapidly recover from power outages and continue operating with electricity, heating, cooling, ventilation, and other energy-dependent services.
Step Load	Step Loads represent large (> 500kW or >1 MW depending on system) new load additions which can come from new buildings, or redevelopment of existing sites. These step loads can include residential developments, C&I, large standalone storage systems, fleet charging operations, and more.
Substations	Unitil's bulk substation steps down transmission level voltages (115kV) to sub-transmission voltage levels (69kV). Unitil's distribution substations steps down sub-transmission voltages (69kV) to distribution level voltages (typically 13.8kV or 4kV).
Supervisory Control and Data Acquisition (SCADA)	SCADA is the system used for visibility and control of the grid.
System Average Interruption Duration Index (SAIDI)	SAIDI indicates the total duration of interruption for the average customer during a predefined period, typically a year. It is commonly measured in minutes or hours of interruption.
System Average Interruption Frequency Index (SAIFI)	SAIFI indicates how often the average customer experiences a sustained interruption over a predefined period of time, typically a year.

Time-Varying Rates (TVR)	Made technically possible by AMI, TVR is a method to manage demand by implementing varying electricity prices at different times of day.
Transformer	A transformer is a device that step-down or step-up the level of voltage.
Transmission	The transporting of electricity through high-voltage lines to distribution lines.
Virtual Power Plant (VPP)	Aggregation of DERs to utilize for grid purposes.
Volt/Var Optimization (VVO)	Volt/VAR Optimization is a technology designed to manage voltage levels and reactive power flow to optimize the efficiency of the distribution grid.

1 EXECUTIVE SUMMARY

Fitchburg Gas and Electric Light Company d/b/a/ Unitil (hereinafter referred to as "Unitil" or "the Company") provides this Electric Sector Modernization Plan (hereinafter referred to as "Plan" or "ESMP") in compliance with the regulations set forth in Massachusetts General Laws Chapter 164 Section 92B – 92C effective August 11, 2022.

The electric system as it is designed today is not prepared for the level of electrification and interconnection of distributed energy resources identified in the Commonwealth's pathway to decarbonization. Investment in the electric system will focus on the overall capacity as well as technological improvements to facilitate an optimized electric system. The long-range forecast focuses the investments where they provide the most benefit

This Plan details the Company's approach to proactively upgrading its distribution (and transmission system where applicable) to: (i) improve reliability and resiliency; (ii) increase the timely adoption of renewable energy resources; (iii) promote energy storage and electrification technologies; (iv) prepare for future climate-driven impacts on the electric system; (v) accommodate increased electrification from transportation, building and other potential demands; (vi) minimize or mitigate the impact to ratepayers while helping the Commonwealth realize its greenhouse gas emission limits.

The Plan is designed to help the Commonwealth realize its Greenhouse Gas ("GHG") Emission limits and as such, the Plan accounts for the Company's share of achieving the goals. This Plan supports a transparent planning process to enable all uses of the electric system while maintaining flexibility to alter the plan to address future challenges that have not yet been identified. The plan provides a 5-year forecast, 10--year forecast and a demand assessment through 2050 to account for future needs. A sensitivity analysis is provided which provides the Company with additional detail on the scope and scale of technology adoption that will have an impact on the load forecasts.

The Company anticipates the ESMP will be an evolving process and that modifications to the Plan will be made from time to time, as a result of (a) changes in technology; (b) customer response to initial ESMP deployments; and (c) experience gained in Massachusetts and other states. The Plan presents the costs of capital investments and expenses for incremental ESMP.

It is Company's intention to seek recovery of existing capital and operating spending programs, pre-authorized programs, and newly proposed ESMP incremental spending through its Grid Modernization Factor tariff because these costs align with the goals of grid modernization. Some types of investments recovered through existing recovery mechanisms – such as energy efficiency investments, existing Grid Modernization and AMI investments, and EV investments, and whenever relevant any approved Capital Investment Projects ("CIPs") – will be recovered through the appropriate already Department-approved cost-recovery mechanism.

The cornerstone of Unitil's approach is the nature of the Company's franchise area and the ability of its customers to afford the rate impact of the proposed ESMP investments. As a result, Unitil's proposed Plan considers both the technical and financial aspects such as rate impacts and the ability of our customers to afford the incremental ESMP investments. Unitil believes this is "a practical approach to electric system modernization" as it places a high value on investments that provide net benefits for customers and have acceptable rate impacts. This approach is consistent with the feedback received from customers.

Climate change is having an effect of increased temperatures and more frequent severe weather events. Resiliency improvements are required to meet these challenges and reduce the impact of major outages to our customers and the communities we serve. The goal of the ESMP is to implement a transparent planning process ensuring the benefits of the plan are distributed in an equitable manner with special attention to providing benefits to Environmental Justice communities and historically disadvantaged communities.

The Company requests the Department to approve the proposed new ESMP spending in this plan and allow recovery of incremental ESMP costs that would not otherwise be recovered through existing cost-recovery mechanisms to be recovered through the Grid Modernization Factor. Given that these costs are aligned with overall grid modernization efforts, if the Department approves the Company's ESMP, the Company will propose to recover the costs of these incremental ESMP investments and expenses through a future Grid Modernization Factor tariff filing. The Company proposes to recover ESMP costs in the same manner as approved in the Company's GMF tariff M.D.P.U. 391. For a typical residential customer, the illustrative bill impact associated with the incremental ESMP investments and expenses for year one is 0.4% or $1.03 per month. Illustrative bill impacts for commercial and industrial customers range from 0.2% to 0.4% when assuming class average usage.

1.1 VISION: ENABLING A JUST TRANSITION TO A RELIABLE AND RESILIENT CLEAN ENERGY FUTURE

Electricity is the lifeblood of modern civilization. It powers homes, businesses, industrial production and even cars. It powers the basic necessities of heat, light, refrigeration and cooking, as well as computers, networks, communication services and entertainment. It keeps us connected. It is essential to our growth, prosperity, standard of living and sense of well-being. Without it, modern society grinds to a halt. Everything runs on electricity. And yet, every kWh of electricity we consume contributes almost a pound of carbon dioxide to the atmosphere.

For over a decade, the Company has visualized the utility of the future as an enabling platform with the capabilities to unlock the full potential of today's customers, markets and technologies. The Company's vision is to transform the way people meet their evolving energy needs to create a clean and sustainable future.

A just transition to a clean energy future means the electric system is designed to meet the needs of all users while not disadvantaging individual or group of customers. The Company will continue to work with our customers, communities and stakeholders to develop electric system plans and approaches to mitigate environmental impacts, support those impacted the most and help the Commonwealth realize its GHG emission limits.

The desire to reduce GHG emissions has driven a transformation of the energy sector. Significant and meaningful investments in clean energy and efficient end-use technologies have led to a decline in GHG emissions. Technology innovation has both accelerated and reinforced this transformation as customers now have access to services, markets and innovative home energy technologies. Advancements in technology are reducing the cost of clean energy, making it more affordable for consumers. Energy markets continue to evolve as innovators develop new tools to control and manage energy usage and market new energy services directly to end-use customers.

As customers adopt new technologies, and as Distributed Energy Resources ("DERs") are increasingly connected to the distribution system, the fundamental architecture of the electricity delivery system must change. The 20th Century electric grid, originally designed to distribute power from large centralized generating plants, must now integrate a wide array of distributed load, storage and generation resources. A grid that was designed for "one way" power flow must now accommodate two-way power flow, increasing the need for sophisticated protection, communication, metering, and intelligence. The grid must also provide opportunities for customers to understand and efficiently participate in energy markets, while delivering improved reliability and power quality.

Utility operations are transitioning away from the traditional model of energy delivery, to one that integrates and optimizes the needs and interests of consumers, producers, markets, service providers and other participants. New markets and new technologies are rapidly emerging in response to changing policies, climate action, and the changing preferences of customers. We are enabling a significant transformation in how customers are powering their homes and businesses, including the ability to generate and store their own electricity. More recently, the promise of affordable electric vehicles has moved from niche to mainstream. Implementing enabling technologies and programs to facilitate these activities will make the electric system more efficient, economic and environmentally friendly.

1.2 PLAN OVERVIEW AND ALIGNMENT WITH THE CLEAN ENERGY AND CLIMATE PLAN

The 2050 Clean Energy and Climate Plan ("CECP") is the Commonwealth's plan to achieve economy-wide net zero greenhouse gas emissions by 2050. The 2050 Roadmap Study, published in December 2020, highlights that electrification and the "All Options" pathway meet the 2050 emissions reduction targets with the least cost while achieving deep decarbonization.[1] The Company has selected the "All Options Pathway" as a key input into the load forecast and demand assessment for 2025-2050. This ESMP is designed to support the Company's portion of the Commonwealth's "All Options" pathway for solar, storage, electric vehicle adoption, and building electrification. The ESMP is Unitil's plan to maintain an electric network that anticipates and meets the needs of significant increases in distributed energy generation, transportation electrification, and increased consumption from policies driving electrification, thereby contributing to the goals of the CECP.

The format of the Plan has been developed with input from the Grid Modernization Advisory Council ("GMAC"). A consistent format for all of the EDCs facilitates an efficient review process. Section 2 of the report describes how this plan complies with the requirements outlined in the 2022 Climate Act. Section 3 provides recommendations for a consistent approach to a stakeholder management process. Section 4 provides some background on the existing electric system as well as some information on technology platforms currently in use. Section 5 describes the 5- year and 10-year electric load forecast and demand assessment used as a basis for ensuring the system is designed to meet future demand.

[1] Massachusetts Clean Energy and Climate Plan for 2050, December 2022, Page 19

Section 6 provides the system constraints and proposed solutions to those system constraints over the 5-year and 10-year terms. This section also provides a summary of the Company's base investments, previously approved investments and new investments proposed as part of this plan. Section 7 provides a summary of the 5-year investment plan. Section 8 describes the Company's approach and assumptions used to develop the 2035-2050 demand assessment. Section 9 provides the system constraints and proposed solutions to those system constraints 2035-2050 timeframe.

Section 10 provides the Company's approach to assessing and planning for the effects of climate change. Section 11 provides an integrated approach to electric and gas distribution system planning. Section 12 describes how this plan will impact the workforce and provide economic and health benefits to our communities. Section 13 provides a summary of the plan as well as a discussion of metrics development and next steps.

The Company, in compliance with the regulations set forth in Massachusetts General Laws Chapter 164 Section 92B – 92C effective August 11, 2022, submitted a draft of this ESMP in September 2023 to the GMAC. The Company along with the other Massachusetts EDCs worked collaboratively with the GMAC and other stakeholders, to collect input into our ESMP. This final version as submitted to the Department of Public Utilities (the "Department") has addressed each of the recommendations received. Each of the GMAC and Equity Working Group recommendations have been responded to and included as attachments to the testimony accompanying this Plan.

1.3 SERVICE TERRITORY OVERVIEW (CUSTOMERS, LOAD, TRANSMISSION, DISTRIBUTION, GENERATION)

The Company's electric service territory includes the towns of Lunenburg, Townsend and Ashby and the city of Fitchburg all located in north-central Massachusetts. The Company provides service to approximately 26,500 residential customers and approximately 4,000 commercial and industrial customers.

The Company's gas service territory overlaps the electric service territory in Fitchburg, Ashby, Townsend and a portion of Lunenburg. The Company also provides gas service to the town of Westminster and the City of Gardner. The Company provides service to approximately 14,500 residential customers and approximately 1,700 commercial and industrial customers.

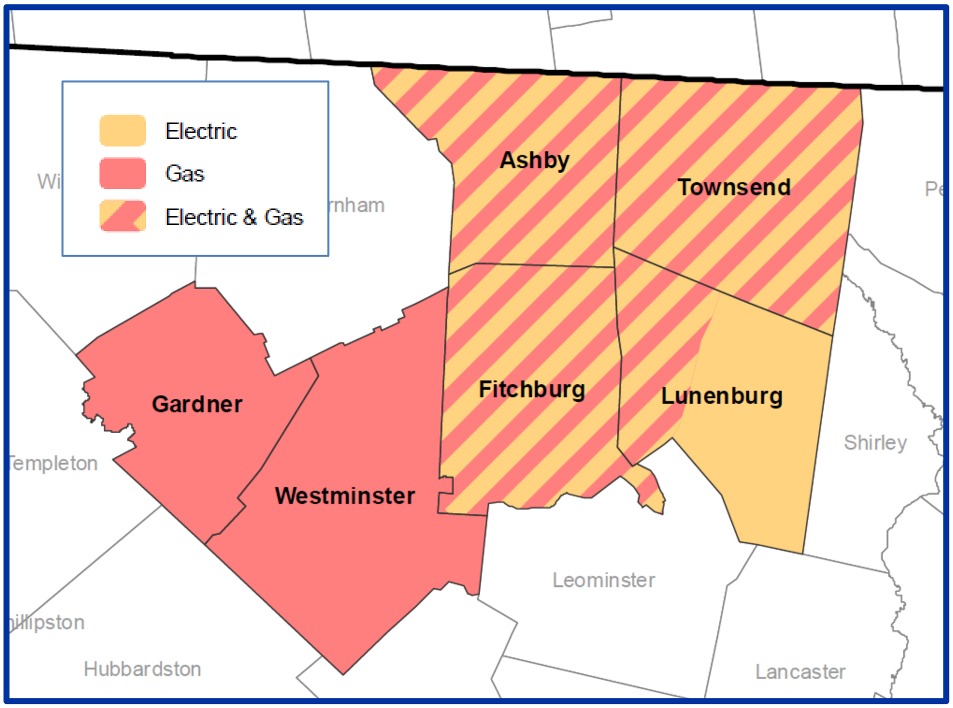

Figure 1 - Unitil's Electric and Gas Service Territory

The Company's electric power system takes transmission service from National Grid's 115 kV transmission system at Flagg Pond substation, located in southwest Fitchburg. Flagg Pond substation consists of a 115 kV high side ring bus, two 115 - 69 kV, 60/80/100 MVA autotransformers, and a 69 kV low side ring bus.

A wood burning non-utility generating facility connects into the system at the Flagg Pond 69 kV ring bus. The facility historically supplies between 12-18 MW to the system.

Seven 69 kV lines transmit power from Flagg Pond substation to ten distribution substations. Transformation at these substations stepdown the 69 kV sub-transmission to the 13.8 kV and 4.16 kV distribution systems. A few 13.8 kV distribution circuits also serve quasi sub-transmission functions as alternate feeds between substations, and as supplies to three other distribution substations with their own 13.8 kV distribution systems.

Four National Grid 115 kV transmission lines terminate at the Flagg Pond 115 kV ring bus. Two of these lines operate in parallel from Pratt's Junction substation in Massachusetts. The other two lines terminate at Bellow's Falls substation in Vermont. However, one of these lines loops in and out of Eversource Energy's Fitzwilliam substation in New Hampshire prior to Bellow's Falls. Both pairs of lines are double-circuited on common towers.

As part of the regional New England bulk power system, the Flagg Pond 115 kV bus and these National Grid transmission lines are New England Power Pool ("NEPOOL") classified Pool Transmission Facilities ("PTF"). PTF facilities are operated by the Independent System Operator of New England ("ISO-NE"), which is responsible for maintaining the integrity of the New England power system.

The electric system reached a peak load for the summer of 2022 of 95.050 MW on August 8th at 7:00 PM.

Unitil's Massachusetts service territory has a high proportion of low-income households, and a high concentration of Environmental Justice ("EJ") populations. In particular, the Massachusetts Executive Office of Environmental Affairs has designated 90.9 percent of the Block Groups within the City of Fitchburg as EJ communities, and approximately 86.3 percent of the total population within the City of Fitchburg reside within an EJ Block.[2] Approximately 65.0 percent of Unitil's Massachusetts customers are located within the City of Fitchburg. The Company has worked diligently within this ESMP to minimize the impact of electric substation infrastructure within an EJ community, while also implementing other investments (i.e., VVO) within EJ communities so these customers can receive benefits early in the plan.

[2] https://s3.us-east-1.amazonaws.com/download.massgis.digital.mass.gov/shapefiles/census2020/EJ%202020%20updated%20municipal%20statistics%20Nov%202022.pdf

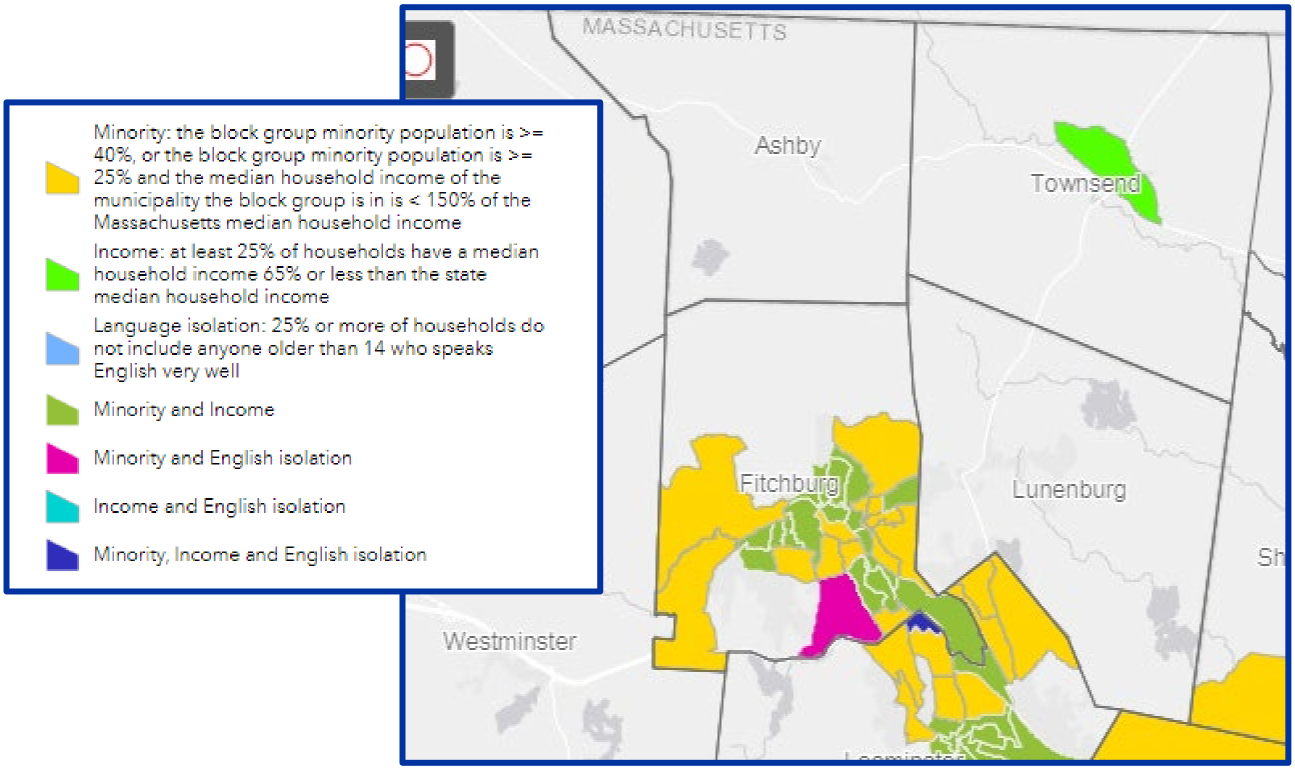

Figure 2 – Massachusetts 2020 Environnmentla Justice Populations

1.4 HOW OUR CUSTOMERS WILL EXPERIENCE THE CLEAN ENERGY TRANSITION

A reliable, affordable and fully modernized electric grid is an essential pillar of modern society. It will power the basic necessities of life while supporting new technologies, services and interactivity. It will operate more efficiently, optimize grid-connected resources and enable dramatic expansion of clean energy to protect and preserve the environment. It will foster innovation and enable new markets by optimizing benefits to customers, service providers and other stakeholders. At its fullest potential, it will harness technology innovation to connect customers, markets, solution providers and new technologies to achieve the full potential of an advanced 21st Century energy system.

To achieve the promise of a fully modernized grid, the Company views the electric grid and the devices connected to it as a communicating, intelligent grid-connected ecosystem of people, devices, information and services. The grid is only a part of this larger energy ecosystem, but it is the foundation upon which everything is built. The role of the utility in this context is to enable seamless grid access, link participants, optimize resources and foster technology innovation. The modern grid isn't just an electrical network, it's a community of grid-connected and grid-enabled customers and third parties.

The utility grid is the foundation upon which a more advanced energy ecosystem will be built. But from a user's perspective, the critical ingredient to achieve the promise of a "Smart Grid" is information. The grid of the future will provide seamless two-way flows of both energy and information. It will be defined not by the electricity it carries, but by the information, functionality and interactive services it provides.

Customers will experience the clean energy transition in many different ways. For example, customers will have the ability to control their own energy usage using timely data and communication from the utility; charge their electric vehicles at multiple locations (i.e., home, work, store, etc.); interconnect distributed energy resources to the electric system; and have the options to heat their homes using heat pumps. Customers will also have the opportunity to enter into demand response programs and modify their electric usage behaviors and benefit from time-varying rates.

1.5 DEMAND ASSESSMENT AND INVESTMENT DRIVERS

The Company has provided two different forecasts. One forecast is based upon a regression trendline and assumes a certain statistical confidence interval based upon historical loading and weather influences. This forecast is used in the near term to identify when system growth is likely to cause system supplies and main elements of the 115 kV, 69 kV and 13.8 kV sub-transmission and substation systems to reach unacceptable design limits, and to provide recommendations for the most cost-effective system improvements. The study examines the electric system under summer peak load conditions in its normal operating configuration and in response to design contingencies for the loss of key system elements.

The second forecast is a demand assessment, which is a longer-range forecast. The demand assessment makes certain assumptions about the adoption rates for electric vehicles; the electrification of the heating loads; and the integration of clean energy resources and energy storage. Very little historical trending can occur for this type of transition. The speed at which the transition will occur will depend on pricing models, government subsidies, technology advancement, supply chain, individual situations (i.e. end of life heating system decisions), etc.

The Company has also provided a sensitivity analysis around the various assumptions within the load forecast. This information provides the Company with additional detail on the scope and scale of technology adoption that will have an impact on the load forecasts.

For the purposes of our analysis, the forecast is used to determine when a system improvement is likely to be required and the demand assessment is used to adequately size the system improvement to ensure the system improvement can address the speed at which the transition may happen.

The figures below show the 2025-2034 forecast and 2035-2050 demand assessment.

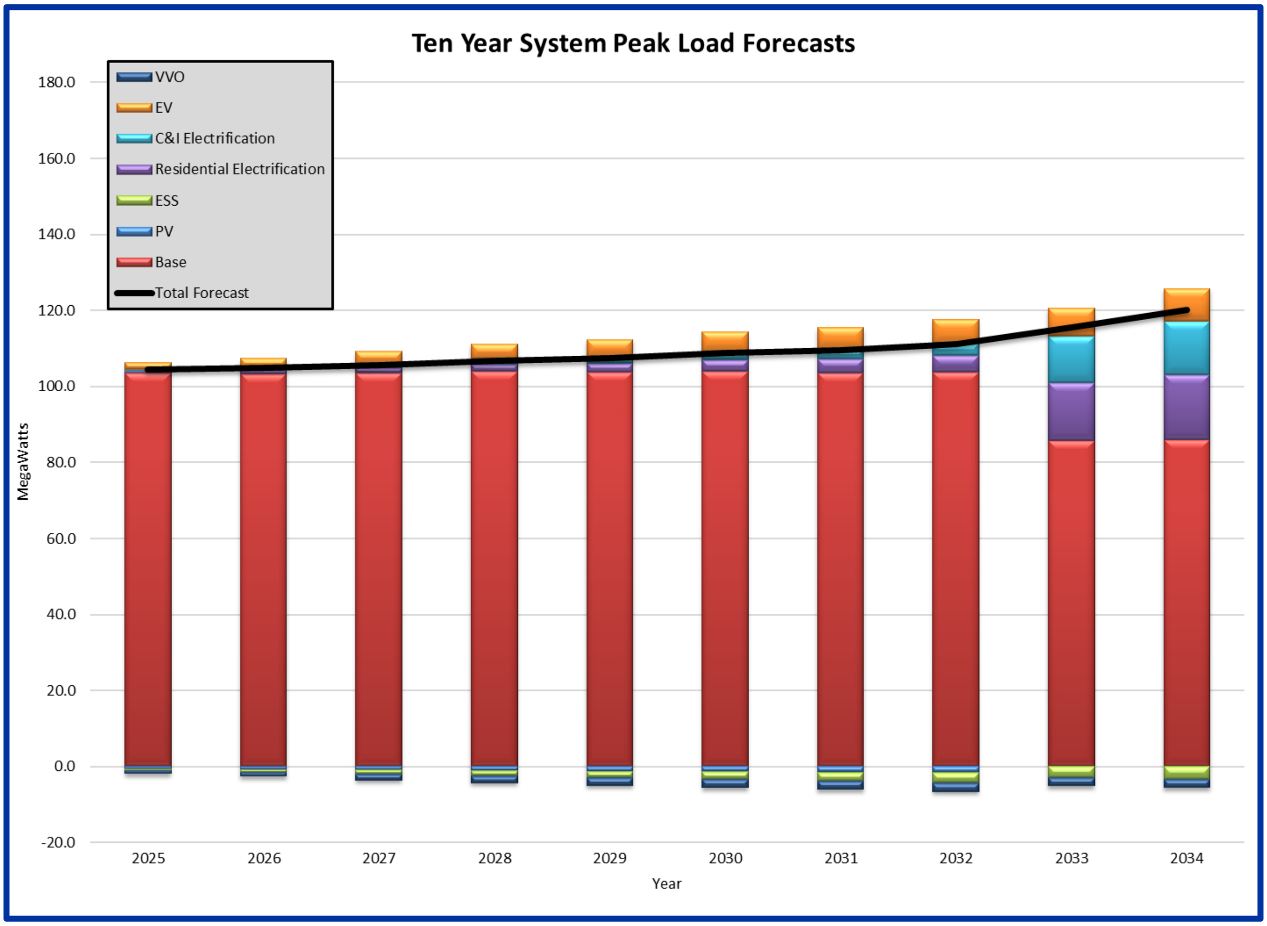

Figure 3 – Ten Year System Peak Load Forecast

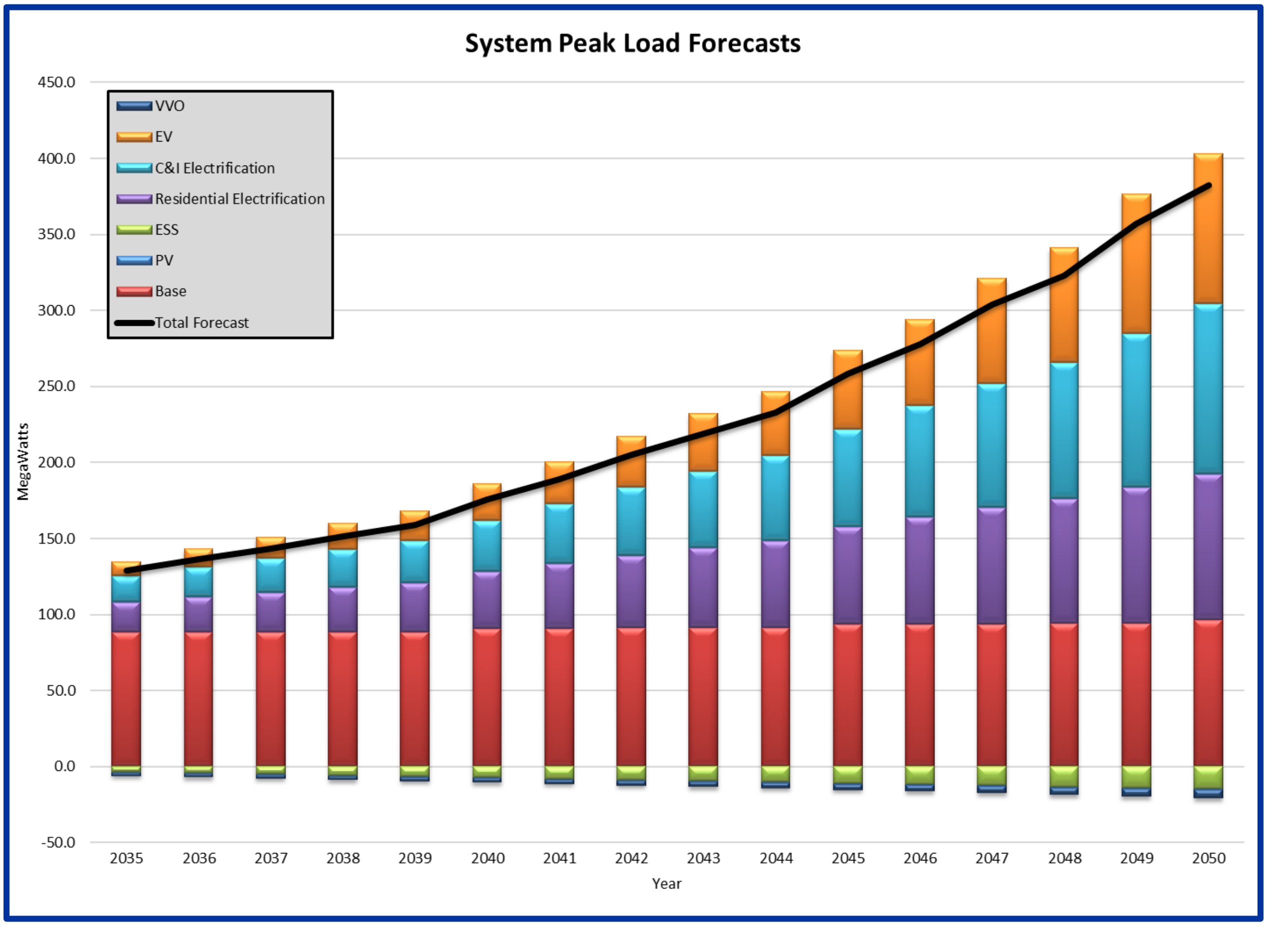

Figure 4 – 2035 - 2505 Demand Assessment

In order for the Company to meet the load forecast and demand assessment, the system will require incremental investments. The table below identifies the estimated increase in the number of substations, miles of distribution lines, number of customers, quantity of poles and number of service transformers associated with this ESMP.

Asset	Existing	2025-2029 Estimate	2030-2039 Estimate	2040-2050 Estimate	2025 – 2025 Total Increase Estimate	2025-2050 % Increase Estimate
Substations	15	16	16	19	4	27%
Distribution (Miles)	522	530	550	570	48	9%
Overhead (Miles)	454	460	470	480	26	6%
Underground (Miles)	68	70	80	90	22	32%
Poles	19,100	19,320	19,740	20,060	960	5%
Distribution Service Transformers	6,500	6,890	7,150	7,410	910	14%
Electric Customers	30,500	31,400	32,900	34,300	3,800	12%

Table 1 – Estimated ESMP Impact on the Electric System

1.6 STAKEHOLDER ENGAGEMENT AND FEEDBACK

The Company believes that stakeholder engagement should begin at the very earliest planning stages for all project types that will impact customers. An effective stakeholder engagement process ensures that customers, municipalities, and other stakeholders understand the ESMP and its role in ensuring the transition to a cleaner energy future. The Company understands the importance of conducting comprehensive outreach in order to engage stakeholders in the planning process and to keep them informed. This includes utilizing Unitil's ESMP-specific Equity Framework to work with a cross-section of customers, communities, EJ stakeholders, low-income and moderate-income customers, municipalities, small and medium businesses, state agencies, community-based organizations, and industry collaborators in order to discuss the important issues at hand.

The Company is committed to educating stakeholders with the hope of establishing a foundational understanding of the electric system, the need for electric sector modernization plans and the Commonwealth's net zero goals. Stakeholder engagement plans will be tailored to each community where significant ESMP infrastructure projects are located with the goal of soliciting feedback and identify concerns and needs. Community concerns will be taken into consideration in the overall siting and design of ESMP projects.

1.7 5-YEAR ELECTRIC SECTOR MODERNIZATION PLAN INVESTMENT SUMMARY AND OUTCOMES ACHIEVED

The Company has taken a practical approach to the 5- and 10-year spending plans associated with this ESMP. This Plan has been developed based upon the Company's relative size and customer demographics. The Company will continue to review and improve on this Plan.

The table below provides a comprehensive view of the capital spending plan including the Company's existing capital spending plan, pre-authorized programs (i.e. EE, grid modernization, and electric vehicles), and newly proposed spending (i.e. capacity projects, extended grid modernization, reliability and resiliency and customer facing programs). This spending plan contemplates an approval of the Company's proposed budget by the Department to authorize the Company to expend funds for incremental ESMP investments up to the proposed budget.

Project / Project Category	2025	2026	2027	2028	2029	2025-2029 Total
Existing and Approved Spending						
Annual Blankets	$ 5,522	$ 5,924	$ 6,695	$ 6,896	$ 7,103	**$ 32,139**
Distribution	$ 1,760	$ 3,771	$ 5,324	$ 5,686	$ 5,856	**$ 22,397**
Substation	$ 3,587	$ 3,811	$ 655	$ 675	$ 695	**$ 9,424**
Grid Modernization	$ 3,608	$ 0	$ 0	$ 0	$ 0	**$ 3,608**
EV Charging and Make Ready	$ 196	$ 196	$ 196	$ 0	$ 0	**$ 588**
Reliability/Resiliency	$1,000	$1,000	$1,100	$1,133	$1,167	**$5,400**
Other	$ 2,019	$ 2,021	$ 1,922	$ 1,980	$ 2,040	**$ 9,982**
Total Existing/Approved	**$17,922**	**$16,723**	**$15,893**	**$16,370**	**$16,861**	**$85,538**
Proposed New Spending						
Enable Grid Services	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
ADMS/DERMS	$ 0	$ 150	$ 75	$ 0	$ 0	**$225**
VVO	$ 0	$4,574	$2,875	$3,092	$2,387	**$12,928**
Automation	$ 0	$ 100	$ 100	$ 100	$ 100	**$400**
FERC Order 2222 Implementation	$ 100	$ 100	$ 0	$ 0	$ 0	**$ 200**
Cyber Security	$ 105	$ 120	$98	$98	$ 98	**$ 519**
Lunenburg Substation	$ 4,400	$ 4,700	$ 0	$ 0	$ 0	**$9,100**
South Lunenburg Substation	$ 3,000	$ 0	$ 7,000	$ 8,000	$ 2,500	**$20,500**
EV Charging and Make Ready	$ 0	$ 0	$ 0	$ 396	$ 396	**$ 792**
Targeted Reliability and Resiliency	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	**$5,000**
Total Proposed	**$8,605**	**$10,744**	**$11,148**	**$12,686**	**$6,481**	**$49,664**
Total Costs	**$26,297**	**$27,467**	**$27,041**	**$29,056**	**$23,342**	**$133,202**

Table 2 – Existing/Approved and Proposed Capital Spending ($000's)

The existing capital budget is broken down into the following categories:

- Annual Blankets - This category includes blanket authorizations for categories of projects where each individual project is small in value (under $30,000) and cannot be individually anticipated at budget time. Typical blanket projects include (but are not limited to): distribution improvements, new customer additions, outdoor lighting, emergency and storm restoration, billable work, and transformer and meters purchases.

- Distribution - These projects are individually authorized projects capacity improvements or equipment replacement on the distribution system.
- Substations - These are individually-authorized projects involving capacity improvements or equipment replacement projects in substations.
- Reliability/Resiliency – These are projects designed and justified specifically to address reliability and resiliency concerns across the system.
- Others – Includes all other small categories of projects including (but not limited to): software/IT projects, communications projects, tools, laboratory, office furniture and office equipment, and improvements to the Company's buildings. In general, these facilities represent only a small portion of the overall budget.

Previously approved project spending are projects and programs that have already received approval from the Department. Those spending categories include:

- Grid Modernization - These are individually-authorized projects that have received pre-authorization under the Company's filed Grid Modernization Plan. This was previously approved in DPU 15-121 and DPU 21-82.
- EV Charging and Make Ready – This is the pre-approved capital spending for EV charging make ready projects. The Department approved a five-year budget in Docket DPU 21-92.

The Company's Plan also includes proposed or incremental ESMP spending. The Company is requesting the Department to approve the proposed budgets for the proposed incremental ESMP projects. The proposed projects include:

- Grid Modernization - These are new or incremental investments in grid modernization projects proposed as part of this ESMP. These projects may be extensions or acceleration of existing grid modernization projects or programs. These projects include ADMS/DERMS, VVO, Automation, FERC Order 2222 Implementation and Cyber Security.
- Network Investments – The Company is proposing two substation projects during this Plan: Lunenburg Substation and South Lunenburg Substation. Both projects are designed to provide additional capacity to serve the load as well as provide the opportunity for circuit modifications to reduce the overall size and customer exposure due to the reduced customer counts.
- EV Charging and Make Ready – This is a proposed extension of the EV make ready program for the years 2028 and 2029 which were not previously approved in Docket DPU 21-92.
- Targeted Reliability/Resiliency – The Company is proposing to incrementally increase investment on targeted spacer cable and undergrounding projects by $1.0 million per

year in an effort to increase the overall resiliency of the electric system. This level of funding will support the installation of approximately 2 miles of spacer cable or 700 to 1,800 feet of targeted undergrounding. This spending may also be used for developing circuit ties where they do not exist or automating circuit ties where they do exist. The Company is proposing to recover this amount with the ESMP incremental investments, while the existing reliability spending would be recovered with its core spending as part of a base rate case.

The table below provides a comprehensive view of the operations and maintenance expense spending categorized by the existing operating expense, previously authorized spending by the Department (i.e. EE, grid modernization, and electric vehicles), and newly proposed spending.

The existing or "business-as-usual" operating expense category includes:

- Electric Operations – Electric operations covers the operations and maintenance of the electric system including but not limited to: distribution maintenance, substation maintenance, street light maintenance, underground maintenance, metering, field services as well as the field and local supervisory labor associated with these activities.
- Professional Services – These are external services the Company retains when additional resources are needed or specialized skills are needed.
- Business Support – Business support includes the functions related to supporting the business, such as, billing, postage, insurance, customer outreach, banking fees, software fees, regulatory assessments, telecom and service company allocations.
- Customer – Customer includes functions such as, costs associated with credit and collections and the provisions for customer bad debt.
- Vegetation Management and Storms – Vegetation Management activities include the cycle pruning, hazard trees and storm resiliency program maintenance activities.

Previously approved spending includes those expenses that have been previously authorized by the Department.

- Energy Efficiency – This category represents the program administration fees associated with the Company's EE program through Mass Save. The amount shown in the table assumes a consistent level of funding based upon the most recent 3-year plan. The Company is not proposing new or additional energy efficiency funding through the ESMP program.
- Electric Vehicles – Electric vehicle expense includes the Department-approved customer refund and reimbursements for residential EV charging facilities. This spending was previously authorized in Docket D.P.U. 21-92.

- Grid Modernization – Grid Modernization expense includes the Department approved grid modernization expenses. This spending was previously authorized as part of Dockets D.P.U. 15-121 and D.P.U. 21-82.

Proposed new or incremental operating expense includes proposed spending includes the following proposed spending:

- Electric Vehicles – Electric vehicle expense includes proposed new or incremental expenses not previously authorized by the Department in Docket D.P.U. 21-92 for the extension of customer refund and reimbursements for residential EV charging facilities.
- Grid Modernization – Grid Modernization expense includes proposed new or incremental grid modernization expenses not previously approved by the Department in Dockets D.P.U. 15-121 and D.P.U. 21-82 for the extension of existing as well as proposed grid modernization projects.
- ESMP Program Administration – The administration of this plan will require funding to be successful. This funding would be used for stakeholder outreach and any measurement and verification efforts (similar to grid modernization).

Project / Project Category	2025	2026	2027	2028	2029	2025-2029 Total
Existing and Approved Spending						
Electric Operations	$ 4,045	$ 4,166	$ 4,291	$ 4,420	$ 4,552	**$ 21,474**
Professional Services	$ 499	$ 514	$ 529	$ 545	$ 561	**$ 2,648**
Business Support	$ 3,751	$ 3,863	$ 3,979	$ 4,098	$ 4,221	**$ 19,912**
Customer	$ 1,602	$ 1,651	$ 1,700	$ 1,751	$ 1,804	**$ 8,508**
Vegetation Management and Storms	$ 2,529	$ 2,605	$ 2,683	$ 2,763	$ 2,846	**$ 13,427**
Energy Efficiency[3]	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	**$ 40,000**
Electric Vehicles	$ 92	$ 92	$ 92	$ 0	$ 0	**$ 276**
Grid Modernization	$ 329	$ 0	$ 0	$ 0	$ 0	**$ 329**
Total Existing	$20,846	$20,890	$21,274	$21,578	$21,985	**$106,573**
Proposed New Spending						
Energy Efficiency[4]	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
EV Charging and Make Ready	$ 0	$ 0	$ 0	$ 184	$ 184	**$ 368**
Enable Grid Services	$ 200	$ 200	$ 50	$ 50	$ 50	**$ 550**
ADMS/DERMS	$ 0	$ 188	$ 199	$ 211	$ 224	**$882**
VVO	$ 0	$ 20	$ 23	$ 30	$ 33	**$ 106**
FERC Order 2222 Implementation	$ 50	$ 50	$ 50	$ 50	$ 50	**$ 250**
Cyber Security	$ 20	$ 20	$ 20	$ 21	$ 22	**$ 103**
ESMP Program Administration	$ 75	$ 75	$ 75	$ 75	$ 75	**$ 375**
Total Proposed	$345	$533	$417	$621	$638	**$2,524**
Total Costs (000s)	**$21,191**	**$21,443**	**$21,691**	**$22,199**	**$22,623**	**$109,147**

Table 3 – Existing/Approved and Proposed O&M Spending ($000's)

This Plan is designed to meet the expected customer outcomes of: 1) improved grid reliability, communications and resiliency; 2) enabling increased, timely adoption of renewable energy and distributed energy resources; 3) promoting energy storage and electrification technologies

[3] The Company is not intending to forecast EE spending as the EE plan and funding levels are adjudicated in a separate process. The table assumes the 2024 Plan spending continues at the same funding level throughout the 2025 - 2029 timeframe.
[4] See FN 3.

necessary to decarbonize the environment and economy; 4) preparing for future climate-driven impacts on the transmission and distribution systems; 5) accommodating increased transportation electrification, increased building electrification and other potential future demands on distribution and, where applicable, transmission systems; and 6) minimizing or mitigating impacts on the ratepayers of the Commonwealth, thereby helping the Commonwealth realize its statewide GHG emissions limits and sublimits under chapter 21N.

The figure below provides an ESMP project timeline overview of when the spending is expected to occur for each project. This figure is for the 2025-2029 timeframe for which the Company is requesting approval of the incremental ESMP investments. Some of these investments may continue into the subsequent ESMP plans, but those will be identified in future ESMP plans.

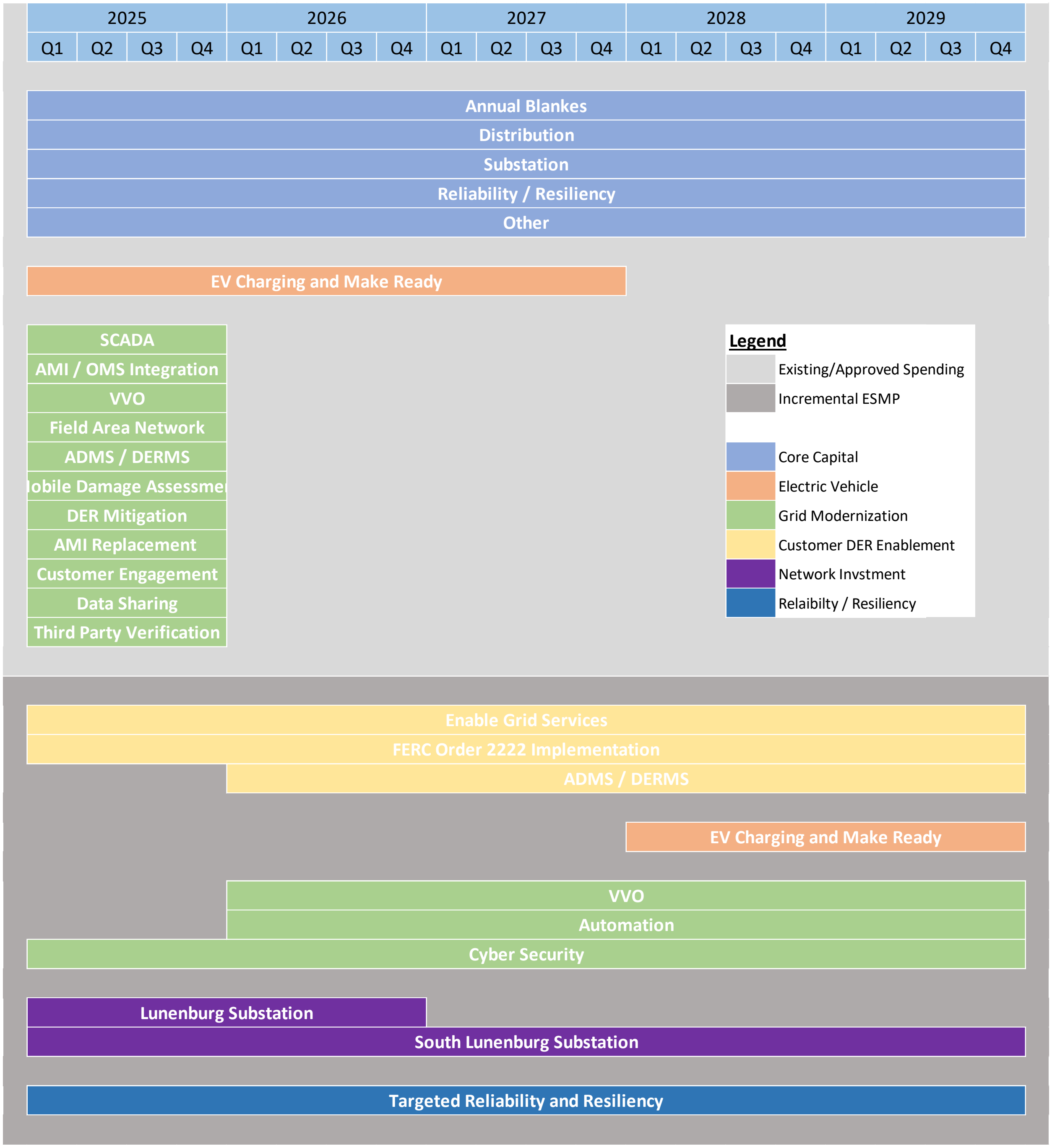

Figure 5 – ESMP Project Timeline Overview

The Company has identified a series of eight objectives that together ensure support of a modern grid: 1) Environmentally Friendly; 2) Safety, Reliability and Resiliency; 3) Customer Enablement; 4) Security; 5) Flexibility; 6) Affordability; 7) Demand and Asset Optimization; and 8) Technical Innovation. Our objectives are crafted with guidance from the United States Department of

Energy, and the Department and are used to identify the investments and technologies that best serve this new era. These objectives align with the statutory requirement as codified in G.L. c. 164, § 92B. The table below maps the existing and proposed projects to the objectives.

Project Or Functionality	Existing / Planned	Environmentally Friendly	Safety, Reliability, and Resiliency	Customer Enablement	Security	Flexibility	Affordability	Demand and Asset Optimization	Technical Innovation
Base Capital Budget	Existing	X	X	X	X	X	X	X	X
Enable Grid Services	Planned	X	X	X	X	X	X	X	X
ADMS/DERMS	Existing and Planned	X	X	X	X	X	X	X	X
VVO	Existing and Planned	X	X	X		X	X	X	X
SCADA Automation	Existing and Planned		X	X	X	X	X	X	X
Cyber Security	Planned		X	X	X				X
FERC 2222 implementation	Planned	X	X	X		X	X	X	X
Lunenburg Substation	Planned	X	X	X	X	X	X	X	X
South Lunenburg Substation	Planned	X	X	X	X	X	X	X	X
EV Charging and Make Ready	Existing and Planned	X	X	X	X	X	X	X	X
Targeted Reliability and Resiliency	Existing and Planned		X	X	X		X	X	X
Energy Efficiency	Existing and Planned	X		X	X	X	X	X	X

Table 4 – Mapping Projects to Objectives

1.8 CLIMATE IMPACTS AND BUILDING RESILIENCE

Climate change has been linked to more severe weather conditions, rising temperatures, rising sea levels, and precipitation patterns. All of these conditions can have an impact on the electric system. Climate-related risks and opportunities are reflected in the Company's strategic planning processes. Operations, and operating excellence, are critical to and driven by the Company's mission and vision, which include deliberate consideration for sustainability and climate change risk and opportunity. The Company's Mission "to safely and reliably deliver energy for life and provide our customers with affordable and sustainable energy solutions" recognizes the critical importance of our energy delivery services and also considers the lasting value sustainability creates for our stakeholders. The Company's Vision Statement, "to transform the way people meet their evolving energy needs to create a clean and sustainable future" is influenced by climate-related risks and opportunities.

The resiliency of the electric system relies heavily on real-time data and next generation technology, as will our ability to communicate disruptions in service to our stakeholders. The implementation of a mobile platform to expedite damage assessment, remote monitoring and control of field devices, and a transition to next-generation smart meters and the associated infrastructure provides the ability to adapt to changing conditions, withstand potentially disruptive events, and recover rapidly from service disruptions.

The Company conducts climate change scenario planning to better understand the implications of climate change. Various climate change scenarios are evaluated to develop potential mitigation and adaptation strategies to address the most likely and most acute risks. Scenarios are derived from the Intergovernmental Panel on Climate Change, and the U.S. Global Change Research Program's Fourth National Climate Assessment[5]. This approach requires a rigorous planning process that supports strong alignment with our long-term objectives. Our strategy is built around three pillars: 1) transformative customer services and energy offerings, 2) modernizing electric and natural gas infrastructure, and 3) accelerating the clean energy transition.

[5] https://nca2018.globalchange.gov/

The Company completed a multi-day exercise to perform two separate climate scenario analyses: 1) model high emissions and climate impacts to the region (RCP 8.5);[6] and 2) forecast curbed emissions and a milder outcome (RCP 2.6).[7] Participants reviewed scenario specific supporting data and project operational, organizational, and financial impacts in each case. Members of the Company's Strategic Management Group were divided into groups with balanced cross functional expertise and tasked with targeting specific focus areas with the purpose of making suggestions on both risk mitigation and the pursuit of opportunities. Results were compiled, ranked by intensity across a risk mitigation 'heat map,' and reviewed to establish common themes, priorities, and alignment to the strategic pillars contained within the Company's existing strategic planning documents.

The results of the climate-related scenario analysis represent an understanding of which physical and transitional risks under which RCPs are material to the Company, and which of these risk areas have the highest risk prioritization. Seven physical risks and four transitional risks for two RCP scenarios (11 total cases) were identified for company specific assessment.

The assessment included identifying the likelihood and impact to the Company as well as the risks, mitigating actions, and opportunities associated with each. Of those 22 cases, six were identified as posing the highest likelihood and impact to the Company. These were Technology; and Policy, Legal, and Regulatory under RCP 2.6 and Temperature Extremes; Hurricanes and Storms; Reputation; and Change in Mean Temperature under RCP 8.5. For each of the six cases, the identified risks, mitigating actions, and opportunities faced were reviewed for inclusion in current strategic planning initiatives. Each of these areas were reviewed for additional data and input need and are incorporated into an internal strategic planning project management plan to continue analysis and further inform strategic planning.

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[6] Representative Concentration Pathways ("RCP") 8.5 refers to the concentration of carbon that delivers global warming at an average of 8.5 watts per square meter across the planet. The RCP 8.5 pathway delivers a temperature increase of about 4.3˚C by 2100, relative to pre-industrial temperatures. RCP stands for Representative Concentration Pathways.

[7] RCP 2.6 (also referred to as RCP3-PD) is the lowest in terms of radiative forcing among the four representative concentration pathways. This particular scenario is developed by the IMAGE modeling team of the Netherlands Environmental Assessment Agency (Van Vuuren et al., 2007).

1.9 WORKFORCE AND CUSTOMER BENEFITS OF A JUST TRANSITION

Economy, Jobs, and Training

To estimate the economic benefits attributable to the EDCs' respective ESMPs, the EDCs have collaboratively employed the Regional Input-Output Modeling System II (RIMS-II), a tool developed by the United States Department of Commerce – Bureau of Economic Analysis ("BEA"). The RIMS-II model serves as a state-of-the-art framework to estimate the economic benefits of capital investments, such as building new facilities or upgrading existing infrastructure. The analysis considers the direct and indirect impacts of such an investment.

The RIMS-II economic analysis uses the "Type I Final Demand Output Multiplier" to estimate the total economic impact of increased investment on the output of a region. Applying the RIMS-II modeling to the total ESMP investments, as outlined in Section 7.1, shows that the Plan will contribute to considerable economic activity for the Commonwealth. Over the span of 2025-2029, these economic benefits (nominal) are estimated at $32 million of additional economic activity generated by the Company's total capital expenditures. When considering only the proposed incremental ESMP capital investments, the additional economic activity calculated is $12 million. Over the ten-year period of 2025 – 2034, the corresponding results are approximately $59 million from the total capital investments and nearly $16 million from proposed ESMP incremental investment.

Additionally, the capital investments are expected to foster job creation across the state and through local industries. The RIMS-II model estimates the total ESMP investments will generate 255 jobs[8] from 2025 to 2029 statewide, and more than 465 jobs statewide during the extended period of 2025 to 2034. When considering solely the proposed incremental ESMP capital investment during the same periods, job creation is expected to be 96 and 127 statewide, respectively.

From a workforce standpoint, technology is rapidly evolving resulting in increased technical and non-technical jobs and open up opportunity for training and growth within the workforce. These jobs are local to our service territories so residents within our communities will have a greater opportunity for employment. We are focused on providing the skills and knowledge needed to

[8] Includes both full-time and part-time positions and are not equivalent to full-time equivalent (FTE) positions

develop and train a workforce that supports the transition to a modern grid while returning economic benefits to the communities that we serve.

Equity, Environmental Justice and Affordability

The Company's service territory has a high percentage of customers who live in an Environmental Justice community or are identified as a low-to-moderate income household. The Company is keenly aware that the future of the electric system, if not implemented in a carefully thought out plan, can have a diverse impact on our customers and the communities we serve. Mitigating the potential adverse effects of a clean energy transition on our customers and communities and promotes the benefits and opportunities the transition can bring to our customers and communities. A just transition to a clean energy future will ensure the benefits of the clean energy transition are shared widely and support provided to those who stand to lose from the transition.

The Company is mindful that affordability is a major concern for all customers and communities, and will continue to support efforts to ensure cost impacts correspond to the benefits that accrue from improved reliability, resiliency, and clean energy investments. In addition to low-income discounts, arrearage management plans, and other customer cost saving programs, the Company's energy efficiency program is essential to reducing energy usage and therefore costs to customers.

The Company has taken a practical approach to developing its ESMP. This ESMP is designed to support the Commonwealth clean energy goals while providing customers with overall benefits that outweigh the costs. The 5-year plan includes $133 million to total investment, of which $50 million is incremental ESMP investments. The incremental investments result in approximately 0.2% to 0.4% increase in bills depending on the rate class. Unitil looks forward to participating in the Department's newly opened inquiry to examine energy burden with a focus on energy affordability for residential ratepayers (D.P.U. 24-15) and any future rate redesign docket opened by the Department.

The Company has proposed an approach to working with the EJ and underserved communities throughout the deployment of this ESMP plan to address their concerns and develop an equitable process. The Company has developed an ESMP specific Equity Framework (see Section 3), that it will continue to apply throughout this and future ESMP planning, outreach and implementation processes. The Company and the Commonwealth should be focused on ensuring that disadvantaged customers and communities are benefiting from proactive investments and participating in the Commonwealth's policy energy vision. This may include ensuring there is funding for expanded assistance programs and low-income bill discount programs, and reforms that support the ability of customers in Environmental Justice populations, especially low-income customers, to participate in customer programs.

1.10 CONCLUSION AND NEXT STEPS

Unitil appreciates this opportunity to present its ESMP. The Plan is designed to detail the Company's plan to proactively upgrade its distribution (and transmission system where applicable) to: (i) improve reliability and resiliency; (ii) increase the timely adoption of renewable energy resources; (iii) promote energy storage and electrification technologies; (iv) prepare for future climate-driven impacts on the electric system; (v) accommodate increased electrification from transportation, building and other potential demands; (vi) minimize or mitigate the impact to ratepayers while helping the commonwealth realize its greenhouse gas emission limits. The Company looks forward to working with the Department and stakeholders in the review and implementation of the Plan.

The Company is specifically requesting Department review and approval of the following:

1. **Compliance with Requirements** - Approval that the Company's ESMP meets the requirements as identified in Massachusetts General Laws Chapter 164 Section 92B – 92C effective August 11, 2022.
2. **Authorization of Incremental ESMP Investments** - The Company requests authorization of these incremental ESMP capital and O&M investments for 2025 – 2029. The incremental investments identified for authorization include capital and O&M investment associated with the following:
    a. Enable Grid Services
    b. ADMS and DERMS
    c. VVO
    d. Automation
    e. FERC Order 2222 Implementation
    f. Cyber Security
    g. Lunenburg Substation
    h. South Lunenburg Substation
    i. EV Charging and Make Ready
    j. Targeted Reliability and Resiliency
    k. ESMP Program Administration
3. **<u>Cost Recovery</u>** - The Company requests the Department approve the proposed new spending in this plan and authorize the Company to expend funds on the incremental

ESMP investments. Given that these costs are aligned with overall grid modernization efforts, if the Department approves the Company's ESMP, the Company will propose to recover the costs of these incremental ESMP investments and expenses through a future Grid Modernization Factor tariff filing. Some types of investments recovered through separate existing recovery mechanisms – such as energy efficiency investments, existing Grid Modernization and AMI investments, and EV investments, and whenever relevant any approved CIPs – will be recovered through the appropriate already Department-approved cost-recovery mechanism.

4. **Rate Redesign** - Defer consideration of potential rate redesign options, including time-varying rates, to a generic proceeding, or other dockets currently open to consider such options.
5. **Capital Investment Project ("CIP")** - Although, at the present time, the Company does not have existing or proposed CIP proposals, the Company supports the other EDCs' proposal that they be permitted to continue to propose CIPs during the 2025-2029 ESMP term that would be funded pursuant to the Departments D.P.U. 20-75-B cost allocation paradigm
6. **Metrics** - Given the compressed statutory timeframe for GMAC review and Department adjudication of the ESMPs, the Company proposes that the Department Defer consideration of ESMP metrics to a different phase of the ESMP dockets, to be commenced after the Department's review of the ESMPs, where the proposed metrics can be considered and developed more extensively, consistent with the process used by the Department to date for Grid Modernization and Electric Vehicle Program metrics in Dockets D.P.U. 21-82 and D.P.U 21-92.
7. **Stakeholder Outreach** – Approval of the Company's approach to stakeholder outreach (see Section 3), CESAG development, proposed equity framework, as well as approval for cost recovery associated with expenses for these activities.

2 COMPLIANCE WITH THE EDC REQUIREMENTS OUTLINED IN THE 2022 CLIMATE ACT

The Company's ESMP has been developed to make meaningful contributions to advancing state climate and energy policy goals articulated in Section 53 of Chapter 179 of the Acts of 2022 (An Act Driving Clean Energy and Offshore Wind; the "2022 Climate Act"), as codified in G.L. c. 164, §§ 92B and 92C. Massachusetts has been at the forefront of policy initiatives that support the advancement of clean energy resources, electrification, reliability and resiliency, decarbonization, and climate-driven economic transition. As the Company continues to support the equitable transition to a clean energy future, continued and accelerated investments will be necessary to a much greater degree than recent history in both the electric distribution and transmission systems in order to support these state climate and energy policy goals, and to meet increasing customer demands for safe, reliable, and resilient electricity. Unitil has been an active partner in achieving the Commonwealth's goals, including past efforts focused on grid modernization and distributed energy resource penetration. Prior investments alone are not sufficient to achieve a comprehensive and holistic transition to a decarbonized economy as envisioned through the Commonwealth's statutes and planning documents including the Clean Energy and Climate Plan for 2050. Accordingly, the Company's ESMP is designed to address all elements of Section 53 of the 2022 Climate Act and propose specific investments and alternatives to investments that will advance the intended purpose of enabling a just transition to a reliable and resilient clean energy future.

2.1 PURPOSE

In accordance with G.L. c. 164, § 92B(a), the Plan has been developed to proactively upgrade the distribution system (and, where applicable, the associated transmission system) to: (i) improve grid reliability, communications and resiliency; (ii) enable increased, timely adoption of renewable energy and distributed energy resources; (iii) promote energy storage and electrification technologies necessary to decarbonize the environment and economy; (iv) prepare for future climate-driven impacts on the transmission and distribution systems; (v) accommodate increased transportation electrification, increased building electrification and other potential future demands on distribution and, where applicable, the transmission system; and (vi) minimize or mitigate impacts on the ratepayers of the Commonwealth, thereby helping the Commonwealth realize its statewide greenhouse gas emissions limits and sublimits under chapter.

2.2 INFORMATION CONSIDERED

The Company's ESMP considers various information in order to propose investments and alternative approaches that improve the electric distribution system in a manner designed to achieve a reliable and resilient clean energy future. These proposed investments and alternatives aim beyond traditional utility maintenance and upgrades, instead focusing on cost-effective solutions for future electrification, renewable and distributed energy resource integration, decarbonization-driven economic and environmental transitions, and customer empowerment. information considered

The Company's ESMP and pre-filed testimony describes in detail each of the following elements, as required by G.L. c. 164, § 92B(b): (i) improvements to the electric distribution system to increase reliability and strengthen system resiliency to address potential weather-related and disaster-related risks; (ii) the availability and suitability of new technologies including, but not limited to, smart inverters, advanced metering and telemetry and energy storage technology for meeting forecasted reliability and resiliency needs, as applicable; (iii) patterns and forecasts of distributed energy resource adoption in the Company's territory and upgrades that might facilitate or inhibit increased adoption of such technologies; (iv) improvements to the distribution system that will enable customers to express preferences for access to renewable energy resources; (v) improvements to the distribution system that will facilitate transportation or building electrification; (vi) improvements to the transmission or distribution system to facilitate achievement of the statewide greenhouse gas emissions limits under chapter 21N; (vii) opportunities to deploy energy storage technologies to improve renewable energy utilization and avoid curtailment; (viii) alternatives to proposed investments, including changes in rate design, load management and other methods for reducing demand, enabling flexible demand and supporting dispatchable demand response; and (ix) alternative approaches to financing proposed investments, including, but not limited to, cost allocation arrangements between developers and ratepayers and, with respect to any proposed investments in transmission systems, cost allocation arrangements and methods that allow for the equitable allocation of costs to, and the equitable sharing of costs with, other states and populations and interests within other states that are likely to benefit from said investments.

Additionally, the Company's ESMP identifies customer benefits associated with the investments and alternative approaches including, but not limited to, safety, grid reliability and resiliency, facilitation of the electrification of buildings and transportation, integration of distributed energy resources, avoided renewable energy curtailment, reduced greenhouse gas emissions and air pollutants, avoided land use impacts and minimization or mitigation of impacts on the ratepayers of the Commonwealth (Sections 6, 7, 12). G.L. c. 164, § 92B(b).

The Company prepared its plan using three planning horizons for electric demand: a 5-year forecast (Section 5); a 10-year forecast (Section 5); and a demand assessment through 2050 to account for future trends, including, but not limited to, future trends in the adoption of renewable energy, distributed energy resources and energy storage and electrification technologies necessary to achieve the statewide greenhouse gas emission limits and sublimits under chapter 21N (Section 8.0). G.L. c. 164, § 92B(c)(i). The Plan also includes a summary of all proposed and related investments (Section 7), alternatives to these investments and alternative approaches to financing these investments (Section 7) that have been reviewed, are under consideration, or have been approved by the Department previously. G.L. c. 164, § 92B(c)(ii).

Finally, the Company has submitted this plan and solicited input, such as planning scenarios and modeling, from the Grid Modernization Advisory Council ("GMAC") established in section 92C, responded to information and document requests from the GMAC and conducted technical conferences and a minimum of 2 stakeholder meetings to inform the public, appropriate state and federal agencies and companies engaged in the development and installation of distributed generation, energy storage, vehicle electrification systems and building electrification systems (Section 3). G.L. c. 164, § 92B(c)(iii). Specifically, the GMAC began meeting in March 2023 to engage in preliminary governance and informational reviews, and upon receipt of the first ESMPs from all three EDCs on September 1, 2023, the GMAC initiated its 80-day long review of the ESMPs. Overall, the EDCs participated in 26 meetings held by the GMAC or its subcommittees, during which the Company provided requested information, responded to questions, and solicited input on the ESMP. The EDCs responded to three information requests during the GMAC review. The GMAC issued its final report on November 20, 2023, including 88 recommendations for the ESMPs. The EDCs hosted joint stakeholder and technical workshops on November 15, 2023, November 28, 2023, and December 7, 2023, to solicit broad stakeholder input to inform the final ESMP. The Company's ongoing stakeholder and community outreach, as well as details regarding its stakeholder and technical workshops, is discussed in Section 3.3, 3.4, and 3.5 of this ESMP.

2.3 MAPPING OF INFORMATION PRESENTED TO STATUTORY AND REGULATORY REQUIREMENTS

The Company is submitting a comprehensive set of pre-filed testimony supported by expert witnesses that address, in detail, how the ESMP meets the statutory requirements noted above. The information required is presented in the table below, along with citations to where such information is presented in either the ESMP, pre-filed testimony, or both:

G.L. c. 164, § 92B(b) Sections	ESMP / Testimony Reference
A summary of all proposed and related investments, alternatives to these investments and alternative approaches to financing these investments that have been reviewed, are under consideration or have been approved by the Department previously	UN-ESMP-1, at Sec. 6.1 and 7.1; UN-Policy/Solutions-1, at Sec. VI and X.
Identification of customer benefits for all proposed investments and alternative approaches to financing those investments	UN-ESMP-1, at Sec. 7.1.3, 7.1.4, and 12; UN-Net Benefits-1 and UN-Net Benefits-3.
Three planning horizons for electric demand, including a five-year and ten-year forecast and a demand assessment through 2050	UN-ESMP-1, at Sec. 5 and 8; UN-Policy/Solutions-1, at Sec. VI; UN-Forecast-1, at Sec. IV and V.
A list of each GMAC recommendation, including an explanation of whether and why each recommendation was adopted, adopted as modified, or rejected, along with a statement of any unresolved issues	UN-Policy/Solutions-2; UN-Forecast-2; UN-Net Benefits-2; UN-Bill Impacts-2; UN-Metrics-2; UN-Stakholder-2.
(i) improvements to the electric distribution system to increase reliability and strengthen system resiliency to address potential weather-related and disaster-related risks	UN-ESMP-1, at Sec. 4.1.9, 4.2, 6, 7, 9, and 10; UN-Policy/Solutions-1, at Sec. VI to X.
(ii) the availability and suitability of new technologies including, but not limited to, smart inverters, advanced metering and telemetry and energy storage technology for meeting forecasted reliability and resiliency needs, as applicable	UN-ESMP-1, at Sec. 6.3, 7.1, 9.1, and 9.7. UN-Policy/Solutions-1, at Sec. VII, VIII, and X.
(iii) patterns and forecasts of distributed energy resource adoption in the Company's territory and upgrades that might facilitate or inhibit increased adoption of such technologies	UN-ESMP-1, at Sec. 5, 6, 8, and 9; UN-Policy/Solutions-1, at Sec. VI; UN-Forecast-1, at Sec. IV and V.
(iv) improvements to the distribution system that will enable customers to express preferences for access to renewable energy resources	UN-ESMP-1, at Sec. 6.3.2.1, 6.5, 7.1, 9, 10, and 11; UN-Policy/Solutions-1, at Sec. VI to X.
(v) improvements to the distribution system that will facilitate transportation or building electrification	UN-ESMP-1, at Sec. 6.3, 6.4, 6.5, 7.1, 9.1, and 9.7.

	UN-Policy/Solutions-1, at Sec. VI to X.
(vi) improvements to the transmission or distribution system to facilitate achievement of the statewide greenhouse gas emissions limits under chapter 21N	UN-ESMP-1, at Sec. 4.2, 6.1, 6.3, 6.4, 6.5, 7.1, 9, 10, and 11; UN-Policy/Solutions-1, at Sec. VI to X.
(vii) opportunities to deploy energy storage technologies to improve renewable energy utilization and avoid curtailment	UN-ESMP-1, at Sec. 4.1.5, 5.1.4, 6.5, 9.1.4, and 9.3. UN-Policy/Solutions-1, at Sec. X.
(viii) alternatives to proposed investments, including changes in rate design, load management and other methods for reducing demand, enabling flexible demand and supporting dispatchable demand response	UN-ESMP-1, at Sec. 6.3, 6.4.2.2, 6.4.3.2, 6.5, 7.1.1, 9.1, 9.3, 9.4, and 9.6. UN-Policy/Solutions-1, at Sec. VI, VII, and X.
(ix) alternative approaches to financing proposed investments, including, but not limited to, cost allocation arrangements between developers and ratepayers and, with respect to any proposed investments in transmission systems, cost allocation arrangements and methods that allow for the equitable allocation of costs to, and the equitable sharing of costs with, other states and populations and interests within other states that are likely to benefit from said investments	UN-ESMP-1, at Sec. 7.1.2 and 9.5. UN-Policy/Solutions-1, at Sec. X.

Table 5 – Mapping Requirements to ESMP

In addition, the Department is requiring the Company to present the following information through pre-filed testimony:

1. How the ESMP complies with each subsection of G.L. c. 164, § 92B.
2. How the distribution and transmission upgrades identified in the ESMP impact safety, security, reliability of service, affordability, equity, and reductions in greenhouse gas emissions. Such testimony and supporting documentation should clearly distinguish between distribution and transmission system upgrades and related costs.
3. How the ESMP provides net benefits to customers. The net benefits analysis must identify the projected benefits and costs, explain the methodology used, identify all assumptions relied on in the analysis, and address whether, how, and why any factors were prioritized in the analysis. This net benefits analysis may include both quantitative and qualitative demonstrations of net benefits.
4. The forecast projection and demand assessment methods that addresses how the methods:

   a. are reasonable, reviewable, and reliable; and
   b. inform planned and proposed investments.
5. Projected bill impacts with one-year, three-year, and five-year outlooks of implementing the ESMPs.
6. The EDC's existing capital planning process(es), demand forecast methods, and decision-making process for distribution system capital investments.
7. Whether, how, and why the ESMP forecasting, timeline, and investment proposal(s), if applicable, differ from the existing capital planning process.

This information can be found in the Company's testimony or in additional testimony supporting the ESMP, as noted in the below table:

Information Required in Pre-Filed Testimony	Citation to Testimony
Compliance with G.L. c. 164, § 92B	The Company has provided a complete set of testimony in compliance with G.L. c. 164, § 92B. Exhibit UN-Policy/Solutions-1 Exhibit UN-Net Benefits-1 Exhibit UN-Forecast-1 Exhibit UN-Bill Impacts-1 Exhibit UN-Metrics-1 Exhibit UN-Stakeholder-1
Impact of Proposed Upgrades	Exhibit UN-Policy/Solutions-1
Customer Net Benefits	Exhibit UN-Net Benefits-1
Forecast Projection and Demand Assessments	Exhibit UN-Forecast-1
Cost Recover and Bill Impacts	Exhibit UN-Bill Impacts-1
Existing Capital Processes, Forecast Methods and Decision Making Process for Distribution System Investments	Exhibit UN-Policy/Solutions- 1
Whether/How ESMP Forecasting, Timeline, Incremental Investments Differ from Existing Process.	Exhibit UN-Policy/Solutions-1

Table 6 – Testimony Submitted in Support of ESMP

2.4 RECOMMENDATIONS FOR ADDITIONAL PHASES OF ESMP DOCKETS OR GENERIC DOCKETS TO ADDRESS ESMP TOPICS

The 2022 Climate Act requires an extensive amount of information to be included in an ESMP, but limits the Department's review to seven months from the date an ESMP is filed. Moreover, each EDC is required to submit their ESMP on the same date, further complicating the Department's review of these comprehensive plans in such a limited timeframe. In addition, the 2022 Climate Act, contemplates consideration by the Department of several issues that, standing alone, might require far longer than seven months to review. The 2022 Climate Act requires the EDCs to provide a statement of unresolved issues arising from the GMAC's review, input, and recommendations. G.L. c. 164, § 92B(d).

Given the broad scope of issues that the Department may determine warrant consideration regarding the ESMPs and the limited time to resolve all issues through the ESMP process to date, the Company, along with the other EDCs, propose the following:

1. Defer consideration of potential rate redesign options, including time-varying rates, to a generic proceeding, or other dockets currently open to consider such options (e.g., with respect to electric vehicle time-of-use rates, D.P.U. 23-84 and D.P.U. 23-85, and with respect to energy affordability with a focus on residential customers, D.P.U. 24-15);

2. Defer review of opportunities to dispatch energy storage technologies to improve renewable energy utilization and avoid curtailment to the currently open dockets addressing new storage tariffs (D.P.U. 23-115, D.P.U. 23-117; D.P.U. 23-126);

3. Defer review of alternative approaches to financing ESMP-proposed incremental CIP investments to a generic proceeding, and continue to allow EDCs to propose CIPs during the 2025-2029 ESMP term that would be funded pursuant to the Department's D.P.U. 20-75-B cost allocation paradigm; and

4. Defer consideration of ESMP metrics to a different phase of the ESMP dockets, to be commenced after the Department's review of the ESMPs, where proposed metrics can be considered and developed more extensively, consistent with the process used by the Department to date for Grid Modernization and Electric Vehicle Program metrics (respectively, D.P.U. 21-80; D.P.U. 21-81; D.P.U. 21-82; D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92).

Each of these recommendations are addressed in further detail in the Company's testimony at Exhibit UN-Policy/Solutions-1 at Section V.

3 STAKEHOLDER ENGAGEMENT

3.1 CLEAN ENERGY TRANSITION: A SHARED RESPONSIBILITY

Unitil believes that stakeholder engagement should begin at the very earliest planning stages. An effective stakeholder engagement process ensures that customers, municipalities, and other stakeholders understand the ESMP and its role in ensuring the transition to a cleaner energy future. The Company understands the importance of conducting comprehensive outreach in order to engage stakeholders in the planning process and to keep them informed. This includes applying Unitil's ESMP-specific Equity Framework to work with a cross-section of customers, communities, EJ stakeholders, low-income and moderate-income customers, municipalities, small and medium businesses, state agencies, community-based organizations, and industry collaborators in order to discuss the important issues at hand.

Unitil is committed to educating stakeholders with the objective of establishing a foundational understanding of the electric system, the need for electric sector modernization plans and the Commonwealth's net zero goals. Stakeholder engagement plans will be tailored to each community where significant ESMP infrastructure projects are located to solicit feedback and identifying concerns and needs. Community concerns will be taken into consideration in the overall siting and design of ESMP projects.

Below, the Company outlines definitions used in our stakeholder engagement processes, our ESMP-specific Equity Framework, and additional relevant information regarding the outreach that the Company has already initiated in the early stages of the ESMP process.

3.2 APPLYING AN EQUITY LENS: COMMON DEFINITIONS

By way of background, a significant portion of Unitil's service territory is designated as an Environmental Justice community. It is critical that these customers understand and receive the benefits available through the ESMP, and have the opportunity to provide feedback on significant distribution infrastructure projects located within the community.

The Company has developed the following ESMP-specific Equity Framework to guide our work in stakeholder engagement. This living document is intended to demonstrate our commitment to hold equity at the center of our outreach and engagement practices relative to the ESMP and to solicit input and feedback from stakeholders, especially those in Environmental Justice and low-income communities.

We recognize that many customers in these communities may face barriers to accessing information regarding the clean energy transition. Our ESMP-specific Equity Framework aims to improve access to information regarding energy infrastructure and programs in their communities.

The Company's ESMP-specific Equity Framework commits to the following principles:

- Engaging proactively with stakeholders by working with trusted community partners to communicate with customers early in and throughout the planning process;
- Increasing education about the need for future infrastructure, what the Company's investment plans may include, and what customer benefits those plans may provide;
- Engaging with customers via a variety of channels that are conducive to ongoing dialogue, open discussion and clear and timely information sharing while reducing communication barriers;
- Broadening our understanding of community and customer concerns and priorities that also consider historical inequities within the community;
- Striving to directly support economic advancement in our communities, in part, by mitigating adverse impacts of proposed projects;

In order to establish consistent definitions throughout our stakeholder engagement process, the Company has defined several key terms (see below). In cases where a state law-provided definition is available, the Company chose to adopt that definition. In an effort to provide consistency among the other EDCs, similar or the same definitions may be used.

The Company adopts the following definitions regarding equity:

- "Equity" means engaging all stakeholders – including our customers and communities – with respect and dignity while working toward fair and just outcomes, especially for those burdened with economic challenges, racial inequity, negative environmental impacts and justice disparities.

- "Procedural equity" focuses on creating transparent, inclusive, and accessible processes for engagement, such that stakeholders and communities impacted by energy projects and programs are given necessary information and opportunity to participate in processes to inform project siting, development, and implementation.

- "Distributional equity" focuses on enabling a more equitable distribution of the benefits and burdens associated with the clean energy transition.

- “Structural equity” focuses on developing processes and decisions that are informed by the historical, cultural, and institutional dynamics and structures that have led to inequities.

The Company adopts all of the following definitions from state law:

- “Energy Benefits” means access to funding, training, renewable or alternative energy, energy efficiency, or other beneficial resources disbursed by EEA, its agencies and its offices.

- “Environmental Benefits” means access to clean natural resources, including air, water resources, open space, constructed playgrounds and other outdoor recreational facilities and venues, clean renewable energy course, environmental enforcement, training and funding disbursed or administered by EEA.

- “Environmental Justice” is based on the principle that all people have a right to be protected from environmental hazards and to live in and enjoy a clean and healthful environment regardless of race, color, national origin, income, or English language proficiency. Environmental Justice is the equal protection and meaningful involvement of all people and communities with respect to the development, implementation, and enforcement of energy, climate change, and environmental laws, regulations, and policies and the equitable distribution of energy and environmental benefits and burdens.

- “Environmental Justice Population” means a neighborhood that meets one or more of the following criteria: (i) the annual median household income is not more than 65% of the statewide annual median household income; (ii) minorities comprise 40% or more of the population; (iii) 25% or more of households lack English language proficiency; or (iv) minorities comprise 25% or more of the population and the annual median household income of the municipality in which the neighborhood is located does not exceed 150% of the statewide annual median household income.

- “Meaningful Involvement” means that all neighborhoods have the right and opportunity to participate in energy, climate change, and environmental decision-making including needs assessment, planning, implementation, compliance and enforcement, and evaluation, and neighborhoods are enabled and administratively assisted to participate fully through education and training, and are given transparency/accountability by government with regard to community input, and encouraged to develop environmental, energy, and climate change stewardship.

3.3 ENGAGING OUR CUSTOMERS AND CLEAN ENERGY PARTNERS

Unitil believes it is important to engage with customers and municipalities in a meaningful manner. Strong dialogue between the Company and external stakeholders will not only ensure greater common understanding of the needs of the grid and proposed infrastructure projects, but will also create opportunities to build a shared understanding, develop collaboration and trust, and engage in continuous outreach with stakeholders. The following information within this section is relative to stakeholder engagement that has already taken place throughout the drafting process of the Company's ESMP. These events took place in the fall/winter of 2023. The continued, forward-looking customer and stakeholder engagement initiatives may be found in Section 3.5 of this document.

Unitil conducted multiple stakeholder meetings in the fall to educate stakeholders and gain feedback on the ESMP. Both in-person and virtual meetings were held, and targeted briefings were added to annual events in which Unitil participates, such as the United Way Heating Forum, to inform key stakeholders and elected officials of the plan. The Company also engaged directly with municipal officials within communities that have identified infrastructure investment plans in the first five years of the Plan. Moreover, Unitil recognizes that sharing information in a widely-accessible format is important to ensure transparency and to encourage engagement. The Company developed an ESMP landing page on its website to detail an overview of the plan, allow visitors to watch recordings of Company presentations, and provide feedback. The landing page also includes the draft ESMP, stakeholder workshop information and meeting materials, translations in Spanish and Portuguese of overview documents, and links to the GMAC website. Because invites were shared with all customers, they also received a link to our landing page. Similarly, the landing page was shared in social media posts alerting customers and the general public of in-person and virtual presentations. The Company has posted presentations to our landing page.

The Company additionally participated in stakeholder workshops in November alongside the other EDCs to gather additional feedback on plan components. Participants invited to the stakeholder group sessions and technical conferences included: 1) members of the GMAC; 2) community and equity-focused groups, business organizations, academic institutions and municipalities; 3) companies engaged in the development of: DG, energy storage, EV systems, and building electrification systems. The stakeholder workshops were facilitated by a common moderator for all EDCs, due to the consistent nature of all three plans. The sessions were noticed in advance and hosted at times recommended by the community groups and were either virtual or hosted at easily accessible locations. Language translation services were provided where appropriate.

Additionally, the Company presented and participated in professionally-facilitated discussion at a quarterly meeting of the Massachusetts Technical Standards Review Group ("TSRG"). The EDCs gave an overview of the ESMP TSRG process and document, while stakeholder discussion focused on the technical aspects of grid modernization.

Below is a timeline of 2023 Stakeholder Events relative to Unitil's ESMP:

- **October 24th**: The Company gave an in-person Company specific presentation at a local, accessible location in Fitchburg, Massachusetts. All customers were invited to this presentation via email. Interpretation services were made available for Spanish and Portuguese speakers. This presentation focused on the ESMP process and its overall goals. Company subject matter experts ("SMEs") present included engineering, legal, and external affairs.
- **November 1st**: The Company utilized time at an annual United Way Heating Forum to give a shortened version of the above-mentioned presentation, summarizing the ESMP process and its overall goals. Company SMEs included external affairs.
- **November 3rd**: The Company held a virtual presentation that mirrored the one given in the in-person presentation on October 24th. Similarly, all customers were invited to this presentation via email. Interpretation services were again made available for Spanish and Portuguese speakers. This session specifically set aside time for industry stakeholders to ask technical questions, and follow up on any questions from the public. Company SMEs present included engineering, legal, and external affairs.
- **November 15th:** The Company participated in the first of two virtual Joint Stakeholder Workshops with the other EDCs. Simultaneous interpretation services were provided based on the most popular languages spoken in each of the EDC's jurisdictions. These sessions were targeted at having a deeper technical discussion with stakeholders, including breakout groups to address specific questions. These sessions was moderated by Janet Gail Besser and Dr. Jonathan Raab. Company SMEs included engineering, legal, and external affairs.
- **November 29th:** The Company participated in the second of two virtual Joint Stakeholder Workshops with the other EDCs. Simultaneous interpretation services were again provided based on the most prevalent languages spoken in each of the EDC's jurisdictions. These sessions were targeted at having a deeper technical discussion with stakeholders,

including breakout groups to address specific questions. This session were also moderated by Janet Gail Besser and Dr. Jonathan Raab. Company SMEs present included engineering, legal, and external affairs. Panelists, members of the public, and additional stakeholders who attended or watched the November 15th and November 29th workshops could provide written feedback for consideration.

- **December 4th**: The Company participated as a panelist at a presentation held by Representative Jeffrey Roy, Chair of the House Committee on Telecommunications, Utilities and Energy ("TUE"). This presentation was similar to that of the November 1st event at the United Way Heating Forum, giving a broad overview of the ESMP process and its overall goals. Company SMEs included engineering and external affairs.
- **December 7th**: The Company presented and participated in professionally-facilitated discussion at a quarterly meeting of the Massachusetts TSRG. The EDCs gave an overview of the ESMP process and document, while stakeholder discussion focused on the technical aspects of grid modernization. Company SMEs present included engineering.

The Company set up a Unitil-specific email and web form to collect feedback that is monitored frequently. Following the filing of the ESMPs, the Company will continue to solicit feedback from the GMAC, customers and stakeholders as necessary and applicable.

3.4 COMMUNITY ENGAGEMENT AND TRANSPARENCY

As mentioned in Section 3.1 of this document, a significant portion of Unitil's service territory is designated as an Environmental Justice Community ("EJC"), and thus it is critical that these customers understand and receive the benefits available through the ESMP and a modern distribution system, and have the opportunity to provide feedback on significant distribution infrastructure projects located within the community. The Company's EJC map is provided below.

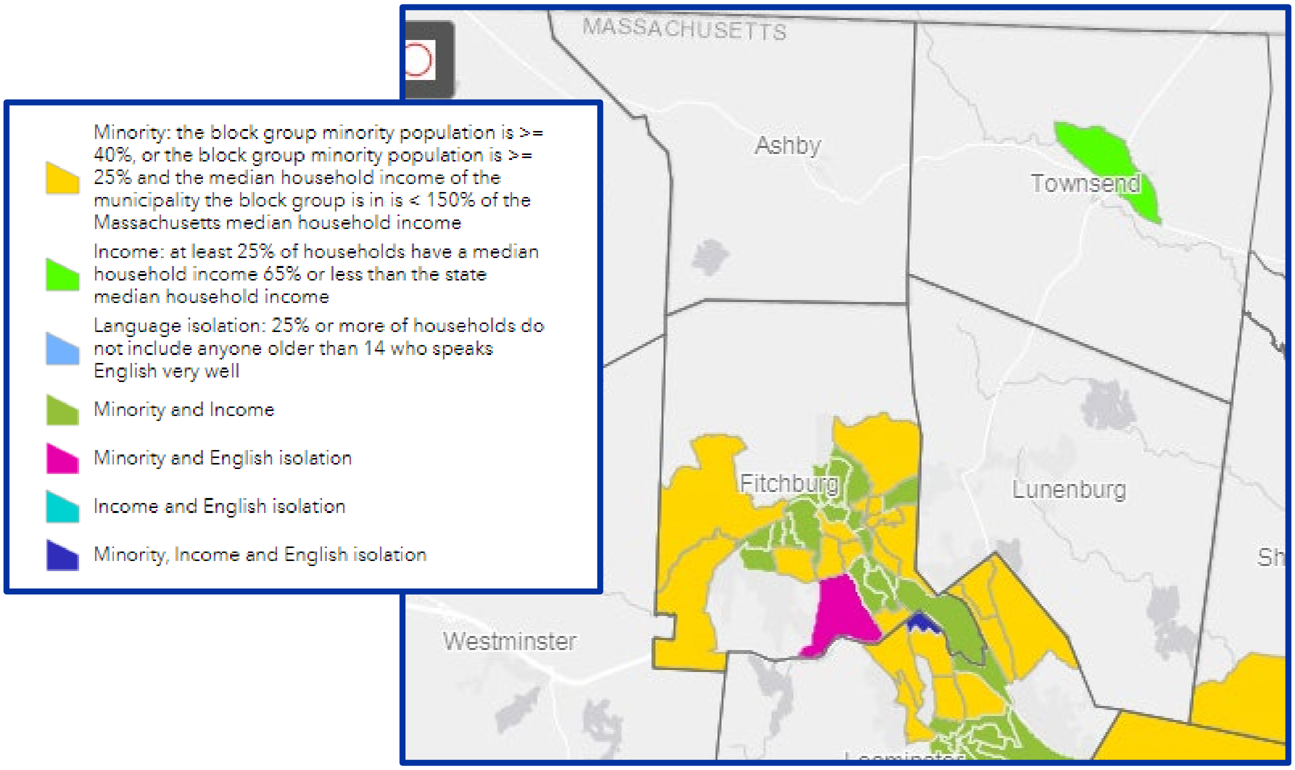


Figure 6 – Massachusetts 2020 Environmental Justice Populations[9]

Outreach specific to EJCs will consider factors essential to ensuring that the communication is effective, including notice, location and accessibility (with consideration given to in-person and virtual participation), and scheduling in a manner that encourages participation and considers language and translation needs. The Company recognizes that further logistical arrangements may need to be made in order to encourage participation and promote accessibility of these materials, specifically in EJCs. This year, the Company engaged with Making Opportunities Count ("MOC"), the leading community action program agency and fuel assistance program administrator for the Company's service region, to determine what arrangements may be helpful for the Company's customers in general. Based on this guidance, Unitil scheduled both in-person and virtual presentations on the ESMP draft, staggered the times of these presentations to ensure greater accessibility and provided translation services in Spanish and Brazilian-dialect Portuguese, the two leading alternative languages used within the service region. Unitil will continue to seek guidance from longstanding community partners like MOC, the United Way, and

[9] https://mass-eoeea.maps.arcgis.com/apps/webappviewer/index.html?id=1d6f63e7762a48e5930de84ed4849212

Fitchburg Housing Authority, to accommodate these requests when feasible. All public-facing materials are reviewed for plainspoken language, visualizations, clarity, transparency, and completeness as part of the drafting and production process.

Municipal outreach is most important when projects or investments will be located within or impact the municipality. It is important to provide the municipality with the knowledge and information required to fully understand the need for the project as well as the scope and impact of the project. With only four electric service territories within the Company's service area, direct, one-on-one meetings with town officials are common on issues of significance within each community. Unitil conducted outreach to officials in all four Unitil electric service communities to ensure each was made aware of the ESMP draft, planned stakeholder sessions and all opportunities to provide feedback.

3.5 CONTINUING COLLABORATIVE ENGAGEMENT AND OUTREACH.

The goal of the stakeholder engagement is to have a transparent and open process that is easy to follow, easy to understand, (including language accessibility) and easy to provide comment and consideration to future projects and future modernization plans. In looking forward to future projects guided by the ESMP, the Company will continue to utilize the engagement practices highlighted in previous sections, as well as identifying improvements and best practices learned to better inform our customers and partners. As summarized, existing engagement practices include Company-specific customer and industry stakeholder sessions; joint EDC community and industry stakeholder sessions (when appropriate); outreach targeted to EJCs; and municipal outreach.

Proposed "Community Engagement Stakeholder Advisory Group"

To further inform EDC engagement efforts around proposed clean energy infrastructure projects discussed in Section 6, the EDCs are developing a Community Engagement Stakeholder Advisory Group ("CESAG"). The CESAG will allow for a structured opportunity for the EDCs to develop a statewide comprehensive stakeholder engagement framework that will:

a) Enable increased transparency and stakeholder engagement around: the complex electrical grid, the EDC distribution planning process through the establishment of a repeatable community engagement platform, and an EDC understanding of the historical inequalities and ongoing disparities by listening to the voices of our most vulnerable customers and communities
b) Ensure our stakeholders feel respected, understood and heard by finding ways to positively engage with communities, and improve our processes to better understand and respond to the needs of our customers to ensure communities that host large clean

energy infrastructure such as substations or associated transmission infrastructure directly benefit from the clean energy enablement infrastructure.

Members and Meeting Frequency:

- Co-chaired by an EDC and a community-based organization ("CBO") (voted upon by CESAG members at the first meeting)
- Composition of nine members with representatives from each EDC (3), representatives from different CBOs across the Commonwealth (5), and an environmental or equity advocate (1)
- CESAG charter and by-laws, including term limits will be co-developed by the EDCs and CBOs with input from the equity representative.
- CESAG would begin meeting in early 2024, meeting two times per month for 4 months to develop a statewide Community Engagement Framework that can be applied to large clean energy infrastructure projects outlined in Chapter 6.
- Once the frameworks are established, periodic review of these frameworks would be conducted as the EDCs implement them.
- Frequency of future meetings would be determined by the CESAG as applicable
- The EDCs support discussing the potential for reasonable compensation to be paid to community-based organizations that are members of the CESAG through a Department generic proceeding
- Meetings will be professionally facilitated.

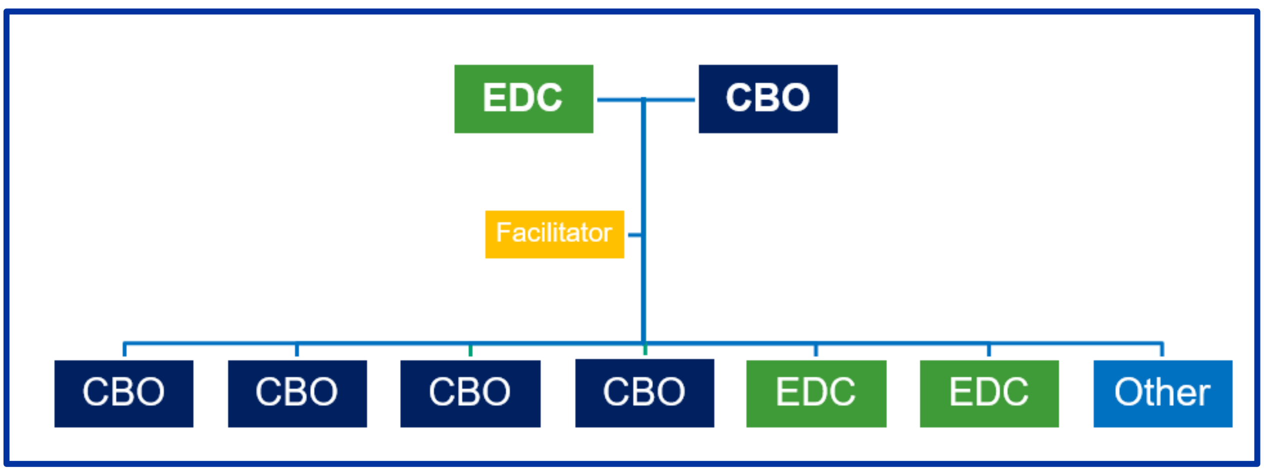


Figure 7 – CESAG Proposed Structure

Community Engagement Framework

With its Clean Energy Climate Plans, the Commonwealth of Massachusetts has established aggressive clean energy targets aimed at transitioning to a decarbonized future. It will be critical to build new distribution infrastructure to accommodate higher penetrations of clean energy and electrification. This new infrastructure needs to be built relatively quickly in order to meet the

Commonwealth's overall decarbonization goals and the near-term interim Clean Energy and Climate Plan emissions reduction targets. Given the need to execute all ESMP projects, the first mandate of the CESAG would be to develop a *Community Engagement Framework* that can be used by the EDCs as an overall guide to working with all potentially impacted communities and stakeholders prior to clean energy infrastructure projects going before the Energy Facilities Siting Board.

This framework will be co-developed and informed by the partnerships at the CESAG. At its core, the EDCs are responsible for providing safe and reliable energy. As we each continue to build and enhance our community engagement efforts, it is important the EDCs remain continuously informed by the voices of our communities. We will further this goal by partnering with community-based experts as part of this process. The best path towards successful and clear community engagement is to have a governing framework co-developed by those stakeholders that live in and engage with communities on a daily basis.

The Community Engagement Framework would enable the following:

- Provide clear principles for EDC outreach and equitable engagement efforts during project development including recommendations around producing non-technical abstracts about proposed projects that can be disseminated to community members and other ways to provide critical information about the impacts and benefits of projects to the public.
- Ensure that historic obstacles to stakeholder engagement such as language barriers or the location/time of engagement sessions are addressed to ensure the widest possible level of community participation.
- Guide the EDCs on best ways to inform and educate communities about the electrical distribution system
- Identify opportunities to support organizations that could help to further cultivate good will and community engagement and/or participation.
- Inform the EDCs on best practices for how community input should be solicited and responded to.
- Define key stakeholders, by categories and specific organizations in specific regions of the Commonwealth.

The goal is for the EDCs to follow a framework co-developed with community partners to allow for greater community engagement, transparency, and support around our clean energy infrastructure projects. Executing a co-developed framework with host communities in advance of project development will ultimately help to advance critical projects necessary as part of the ESMP to accelerate decarbonization in the Commonwealth. As the EDCs continue to learn and grow in this space, the CESAG will continue to identify ways the EDCs can adjust early outreach and engagement strategies in response to feedback from partners, allies and communities.

Community Benefits Agreements

To ensure that communities that host clean energy infrastructure directly benefit from the infrastructure that is built in their community, a connection between the clean energy infrastructure and specific benefits received for hosting that infrastructure is necessary. Such community benefits agreements ("CBA") can take shape as individual EDCs work with a clean energy host community to develop a community benefits agreement specific to that community. No two communities are created equal. Therefore, CBAs will be developed and executed on an individual host community basis. As CBAs are developed with host communities, the EDCs will take feedback and lessons learned from that process back to the CESAG to further ensure all EDCs and CBOs continue to re-think and formulate new methods and approaches to drive benefits of this just transition across the Commonwealth.

4 CURRENT STATE OF THE DISTRIBUTION SYSTEM

This section describes the current state of the Company's electric distribution system. The section begins with a description of the distribution system including customer demographics, and economic development. The section continues by describing DER adoption, grid services, and capacity deficiency, age of distribution and substation infrastructure, provides information on the reliability and resilience of the distribution system. The section ends by describing the siting and permitting process.

4.1 STATE OF THE DISTRIBUTION SYSTEM AND CHALLENGES TO ADDRESS

For decades, the Company has operated and maintained a safe and reliable electric system. Investments made each year are chosen to foster continued improvement in the safety and reliability of the electric system. The primary challenges facing the Company and its electric system are:

- <u>Two-way Power Flow</u> – In traditional electric systems, the electricity flowed in one direction. Large electric generating plants are connected to the high voltage lines of the transmission system. The electric power flows from the transmission system, through the substations, to the electric customers connected to the distribution system. Presently the distribution system is transforming such that, with concentrated installation of DER on the distribution system, the power flow is bi-directional within in the distribution system and the amount of solar generation on the distribution system affects the dispatching of large synchronous generators on the transmission system. System control and protection is more challenging with bi-directional power flow.
- <u>Aging Infrastructure</u> – While upgrading portions of the distribution system for increased capacity needs is required, in order to continue to provide safe and reliable service and transition to a decarbonized future, replacement and upgrade of the existing aging infrastructure is also necessary. Increasing age of equipment may lead to increased outage risk and increased capacity deficiencies as their age worsens.
- <u>Increase in DER adoption</u> – Power generation DER has created challenges to the operation and planning of the distribution system where, due to the aggregate of the DER, power can now flow in both directions. Planning of system capacity must now be analyzed during peak load times as well as light load and high generation times. In addition to capacity analysis, the operation of the distribution system equipment must be considered to ensure the equipment will operate correctly during reverse power flow. Specifically, protective devices and voltage regulating devices need to be designed to operate

correctly in both directions. The variability of solar and ESS can create real-time power quality and reliability concerns in the operation of the distribution system.

- Increasing Customer Loads due to Electrification – The pace at which electrification occurs on the system will increase loads. Upgrades to the electric system to facilitate the loads takes time to implement. The Company will continue to evaluate load forecasts on an annual basis to identify changes in adoption rates that may increase loads more quickly.
- Reliability and Resiliency – Electrification will increase the need for improved reliability and resiliency of the system. Climate change may have an impact with more frequent and more severe storms. The Company's vegetation management program (including its cycle pruning and Storm Resiliency Program) has a large impact on the reliability performance of the Company.
- Siting and Permitting – Siting new electric infrastructure can be a challenging endeavor. The siting process takes time and patience. Delays in the siting process may have an impact on the electric systems ability to maintain pace with increasing loads in support of the Commonwealth's climate goals. Policy and structural changes to the Energy Facility Siting Board process may increase the efficiency and speed of the siting process.
- Effects of Climate Change - Climate change is having an effect of increased temperatures and more frequent severe weather events. Resiliency improvements are required to meet these challenges and reduce the impact of major outages to our customers and the communities we serve.
- Monitoring and Control of the Electric System – The importance of real-time monitoring and control of the electric system becomes increasingly more important as the system becomes more complex. The Company will need to use information from all of its systems to operate a safe and reliable system.

4.1.1 The Electric Grid – An Overview

The electric grid generally consists of the transmission system, sub-transmission system, and the distribution system. These systems are connected to each other through substations. The transmission system consists of a grid of high voltage lines that interconnects and transfers high amounts of power across many states. No customers are served directly from the transmission system. Traditionally the large generating stations providing power to the region are connected directly to the transmission system. The transmission grid is designed and planned such that a loss of an element does not affect the electric customers. The transmission system is regulated by the Federal Energy Regulatory Commission ("FERC") and is planned and operated by an area independent transmission operator. The planning and operation of the transmission system includes planning outages of transmission facilities and dispatching the generating facilities connected to the transmission lines and those enter into the power market. The transmission operator for New England is ISO-NE. The transmission lines typically operate at 115 kV and higher.

The sub-transmission system conducts electricity between the major transmission system to regional distribution substations. Sub-transmission systems are operated by the regional electric company and typically operate at 34.5 kV to 69 kV.

Substations are the points of the electric grid where transmission lines and sub-transmission lines are connected to distribution feeders. The systems are connected at the substations through large circuit breakers, switches, power transformers, voltage regulating equipment, and automatic protection control equipment. The circuit breakers operate to energize and de-energize lines and are controlled by automatic protection schemes to protect the transmission lines and substation equipment from failure. The power transformers lower the voltage from the transmission high voltage to a lower operating voltage of the distribution system.

The distribution system originates at substations supplied from the transmission or sub-transmission system and is operated at medium voltages (typically 34.5 kV and below), and consists of distribution feeders (circuits), poles, transformers, protection devices, voltage regulators and other equipment to supply reliable electric service to the end customer within required voltage levels. The protection devices (circuit breakers, reclosers, fuses, etc.) automatically open to de-energize circuits or sections of circuits to isolate as few customers due to short circuit (fault) on the system. Typically, when the protection devices open, all the customers down-line from that device are out of power. Although there may be protective devices or switches interconnecting one distribution circuit to another, unlike the transmission system, typically the distribution system is designed with power flowing in one direction from the substation to the customer. Therefore, when there is a fault on the distribution system, the power flow to the customer is interrupted, until the system can be reconfigured and repairs to the faulted area can be made.

The Figure below displays the elements and power flow of a traditional electric system.

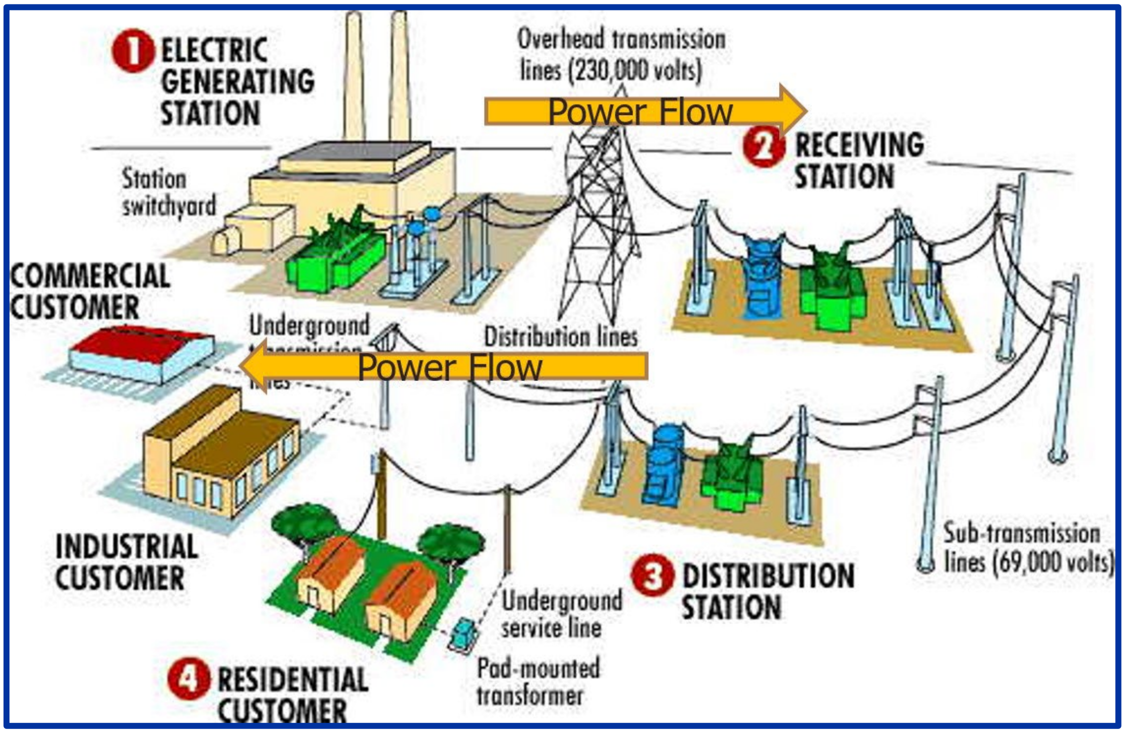


Figure 8 – Traditional Electric System (source Energy Council of the North East)

In traditional electric systems, the electricity flowed in one direction. Large electric generating plants are connected to the high voltage lines of the transmission system. The electric power flows from the transmission system, through the substations, to the electric customers connected to the distribution system. In this configuration, the distribution system is dependent on the transmission system, and the transmission system is rarely affected by events on the distribution system.

Presently the distribution system is transforming such that, with concentrated installation of DER on the distribution system, the power flow is bi-directional within in the distribution system and the amount of solar generation on the distribution system affects the dispatching of large synchronous generators on the transmission system.

Unitil's electric power system is presently supplied from the National Grid's 115 kV transmission system. Service is taken from National Grid at a 115 kV to 69 kV transmission substation owned and operated by Unitil. The transmission substation consists of a 115 kV high side ring bus, two 115 to 69 kV autotransformers, and a 69 kV low side ring bus.

Within the Unitil electric system, there are seven 69 kV (sub)transmission lines interconnecting the transmission substation with ten distribution substations. Transformation at these substations stepdown the 69 kV (sub)transmission to the 13.8 kV and 4.16 kV distribution systems. A few 13.8 kV distribution circuits also serve quasi sub-transmission functions as they are alternate feeds between substations, and supplies to other distribution substations with their own 13.8 kV distribution systems.

The figure below displays the approximate location of the Unitil substations.

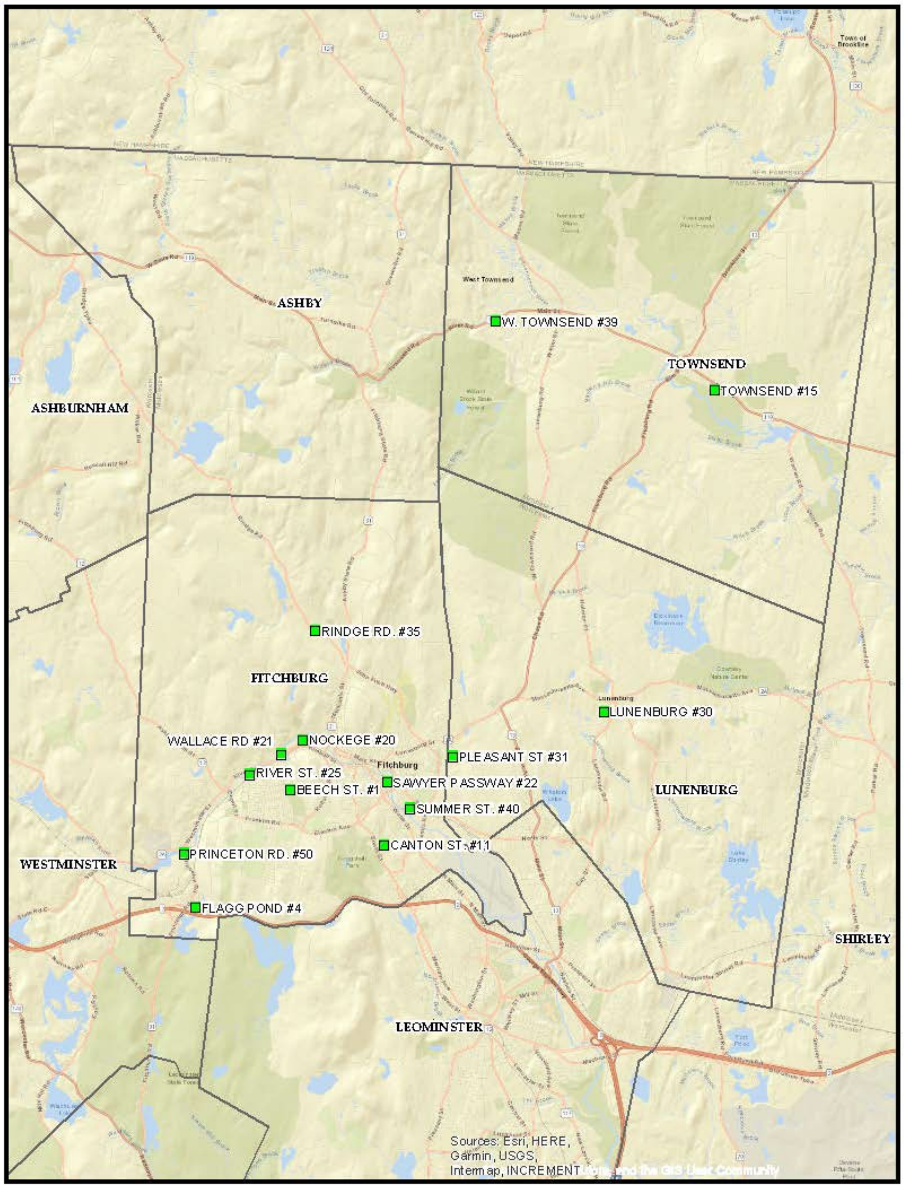


Figure 9 - Unitil Substation Location Map

As noted above, the power flow is bi-directional within the distribution system and even from the distribution system through the bulk substations to the transmission system. The transmission system is more affected by power flows and events on the distribution system. At light load times in the past, the solar generation has supplied more than the total demand on the electric system and has reversed the power flows at the transmission interchange such that power flowed from the 13.8kV distribution system, through the 69 kV sub-transmission system onto the 115 kV New England transmission system.

4.1.2 Customer Demographics

The Company serves approximately 30,000 customers in the cities and towns of Ashby, Fitchburg, Lunenburg and Townsend, and individual services in Leominster, Shirley, and Westminster. Approximately 85% of the customers are residential. The table below details the number of customer accounts broken down by rate class.

Customer Rate Class	Count	Description	% of Total Accounts
R-1	19,832	Residential	65.7%
R-2	5,025	Residential Assistance	16.6%
R-3	1,012	Residential Heat	3.4%
R-4	238	Residential Heat -Assistance	0.8%
G-1	2,511	Small Commercial/Industrial	8.3%
G-2	1,551	Medium Commercial/Industrial	5.1%
G-3	29	Large Commercial/Industrial	0.1%
Special Contracts	2		
Total	30,200		

Table 7 – Customer Count by Rate Class

Based upon the Massachusetts Census Data from 2020,[10] the City of Fitchburg ("Fitchburg") has a population of 41,946, while the towns of Lunenburg, Townsend and Ashby have populations of 11,782, 9,127 and 3,193 respectively. The total population of the four cities and towns with the Company's electric service territory is 65,598 or 0.9% of the Massachusetts population of 7,029,917.

[10] Massachusetts Census Data (malegislature.gov)
https://malegislature.gov/Redistricting/MassachusettsCensusData/CityTown

<u>Environmental Justice Communities:</u>

In Massachusetts, beginning in June 2021, a neighborhood (i.e., a census block group) is defined as an EJ community if any of the following are true: (1) the annual median household income is equal to or less than 65 percent of the statewide median ($81,468 for a household of four in 2021), (2) minorities compromise 40 percent or more of the population, (3) 25 percent or more of households lack English language proficiency (English isolated), or (4) minorities compromise 25 percent or more of the population and the annual median household income of the municipality in which the neighborhood is located does not exceed 150 percent of the statewide annual median household income.

In particular, the Massachusetts Executive Office of Environmental Affairs has designated 90.9 percent of the Block Groups within Fitchburg as EJ communities, and approximately 86.3 percent of the total population within Fitchburg reside within an EJ Block. Approximately 65.0 percent of Unitil's Massachusetts customers are located within Fitchburg. The figure below displays a map of the EJ communities in Unitil's territory.

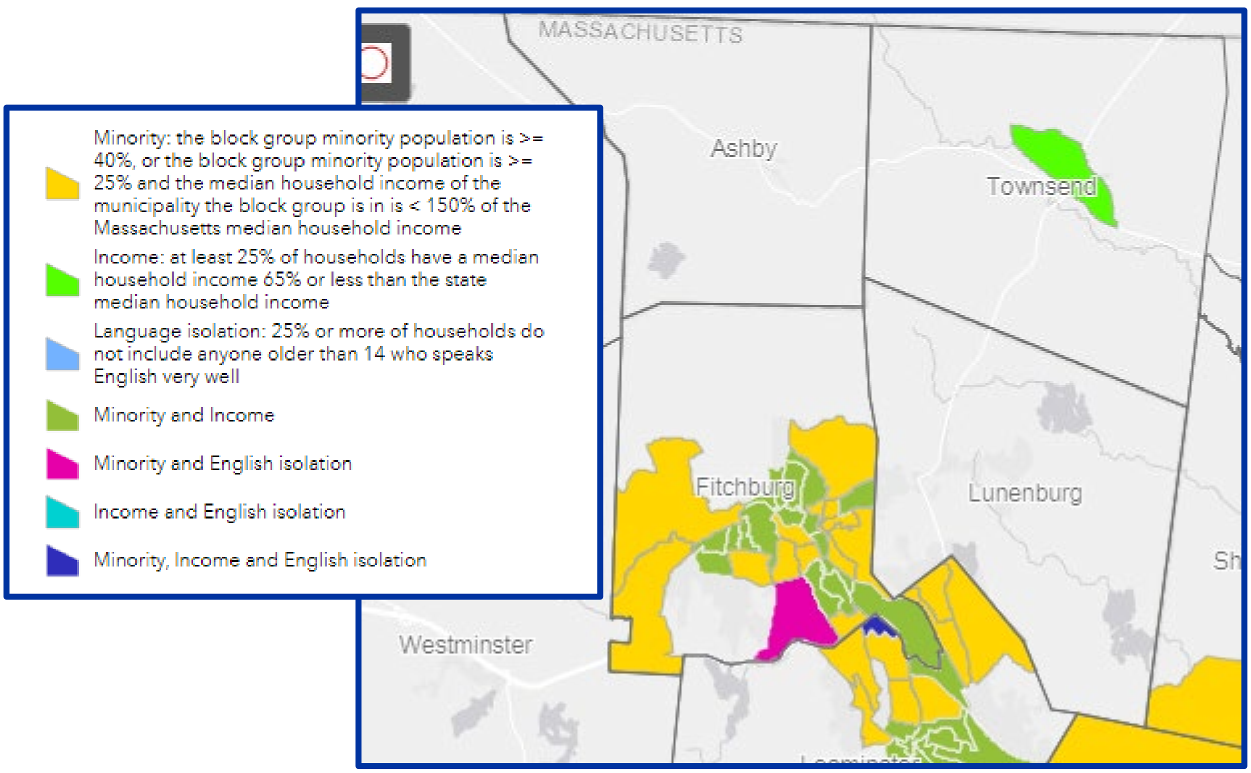


Figure 10 – Massachusetts 2020 Environmental Justice Populations

The table below identifies the percent of EJ community and non-EJ community customers by circuit throughout the service territory.

Substation	Circuit	EJC Customers	Non EJC Customers	% EJC Customers	% Non-EJC Customers
Beech St.	F01W01	617	0	100%	0%
Beech St.	F01W02	2001	0	100%	0%
Beech St.	F01W04	1672	0	100%	0%
Beech St.	F01W06	1	0	100%	0%
Canton St.	F11H10	759	0	100%	0%
Canton St.	F11H11	373	0	100%	0%
Canton St.	F11W11	1226	562	69%	31%
Townsend	F15W14	1	0	100%	0%
Townsend	F15W15	1	0	100%	0%
Townsend	F15W16	20	1516	1%	99%
Townsend	F15W17	339	235	59%	41%
Nockege	F20W22	570	349	62%	38%
Sawyer Passway	F22W1	2119	0	100%	0%
Sawyer Passway	F22W10	0	0	-	-
Sawyer Passway	F22W11	0	0	-	-
Sawyer Passway	F22W12	1	0	100%	0%
Sawyer Passway	F22W17	46	0	100%	0%
Sawyer Passway	F22W2	0	0	-	-
Sawyer Passway	F22W3	20	0	100%	0%
Sawyer Passway	F22W8	2	0	100%	0%
Sawyer Passway	FSNTWK	457	457	50%	50%
River St.	F25W27	380	858	31%	69%
River St.	F25W28	604	37	94%	6%
River St.	F25W29	3	0	100%	0%
Lunenburg	F30W30	0	1427	0%	100%
Lunenburg	F30W31	0	1702	0%	100%
Pleasant St.	F31W34	1258	25	98%	2%
Pleasant St.	F31W37	574	680	46%	54%
Pleasant St.	F31W38	4	1280	0%	100%
Rindge Rd.	F35W36	78	732	10%	90%
West Townsend	F39W18	250	1734	13%	87%
West Townsend	F39W19	0	1335	0%	100%
Summer St.	F40W38	67	0	100%	0%
Summer St.	F40W39	372	1	100%	0%
Summer St.	F40W40	1507	80	95%	5%
Summer St.	F40W42	1646	275	86%	14%
Princeton Road	F50W51	659	2	100%	0%

Princeton Road	F50W53	1	0	100%	0%
Princeton Road	F50W55	141	53	73%	27%
Princeton Road	F50W56	150	1	99%	1%

Table 8 – EJC and Non-EJC Customers by Circuit

4.1.3 Economic Development

The labor statistics for the Leominster-Gardener-Fitchburg area show that the labor rates have not fully recovered to pre-pandemic levels. The number of people in the labor force were steadily increasing prior to 2020, and in 2022 the number was lower than the labor rate of 2017. The 2022 unemployment rate was equal to the rate in 2017. The table below shows the labor statistics of the area from the U.S. Bureau of Labor.

	Labor Force		Employment		Unemployment		Unemployment Rate	
Year	**Number**	**Change**	**Employed**	**Change**	**Unemployed**	**Change**	**Rate**	**Change**
2013	75,275		69,113		6,162		8.20	
2014	76,271	1.3%	71,006	2.7%	5,265	-14.6%	6.90	-15.9%
2015	76,323	0.1%	71,937	1.3%	4,386	-16.7%	5.70	-17.4%
2016	76,935	0.8%	73,249	1.8%	3,686	-16.0%	4.80	-15.8%
2017	79,490	3.3%	75,969	3.7%	3,521	-4.5%	4.40	-8.3%
2018	81,821	2.9%	78,540	3.4%	3,281	-6.8%	4.00	-9.1%
2019	81,251	-0.7%	78,346	-0.2%	2,905	-11.5%	3.60	-10.0%
2020	79,807	-1.8%	71,519	-8.7%	8,288	185.3%	10.40	188.9%
2021	79,196	-0.8%	74,153	3.7%	5,043	-39.2%	6.40	-38.5%
2022	78,593	-0.8%	75,167	1.4%	3,426	-32.1%	4.40	-31.3%

Table 9 – Labor Statistics Fitchburg-Leominster-Gardener Area

4.1.4 Electrification Growth

The Company's EV charging and make-ready program was approved by the Department in D.P.U. 21-92, (Order, December 20, 2022). The program is designed to support the growth of EVs in Massachusetts by providing incentives to public and residential charging. There are approximately 100 zero emission electric vehicles and 900 hybrid vehicles registered within the service territory.[11]

The Company has implemented an online application form for notification of locations where customers intend to install EV chargers. This will enable the Company to ensure that capacity is installed to serve the EV charging stations where demand is shown. The online application form also provides a link for customers to apply to the EV Make Ready Program, which commenced in 2023. As of December 2023, the Company has not received any applications for participation in the EV Make Ready Program. Currently, one auto dealership in the service territory has installed EV charging stations that will be made for public use in the future. Four other auto dealerships, and five residential customers, have provided notification of the intention to install EV charging stations. These are not intended for public use.

The Company, through the MassSave Energy Efficiency Plan, provides incentives to customers to install heat pumps. There are approximately 1,000 heat pumps installed in the service territory. Most of the systems being installed at this point are hybrid heating systems.

4.1.5 DER Adoption

Although Unitil customers account for approximately 0.85% of the electric power sales in Massachusetts, about 1.6% of the total solar generation in the Commonwealth is provided by systems connected to the Unitil distribution system. Approximately 12% of the Unitil electric customers have DG in service or approved to install at their residence or facility. At hours of peak generation, the Unitil system has experienced reverse power flow from the distribution system through the 69kV sub-transmission system to the ISO-NE operated 115kV transmission lines.

The chart below shows the amount of DG and ESS interconnected to the Unitil system with the peak load and the minimum day-time load at the system supply point, for the past ten years. This illustrates that in recent years, at times peak generation during shoulder months, approximately 100% of the system load is supplied by the generation interconnected to the distribution system. The total amount of generation capacity is approximately 70% of the historical system peak load.

[11] As of 1/1/2023 https://geodot-homepage-massdot.hub.arcgis.com/pages/massvehiclecensus

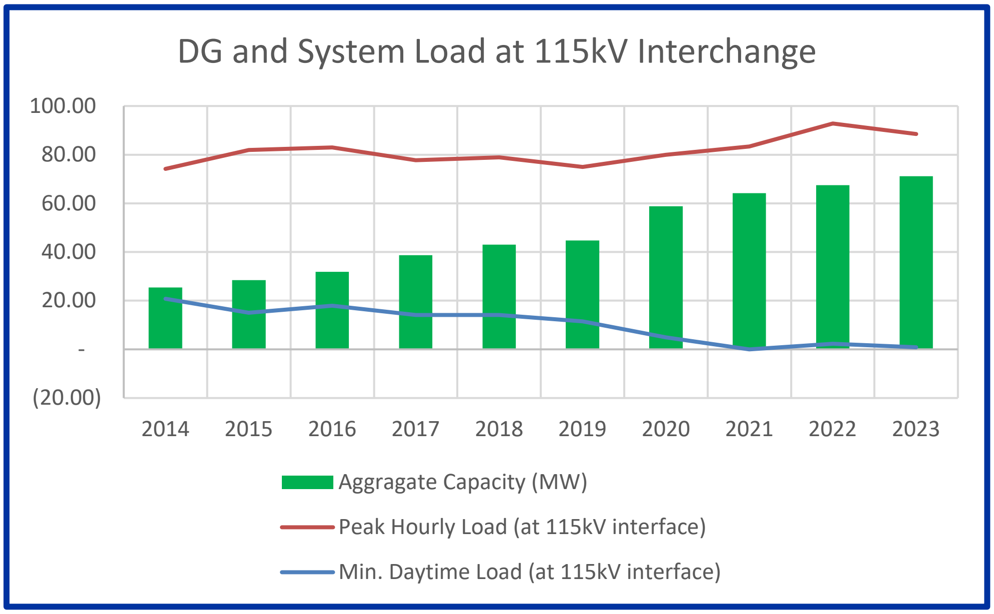


Figure 11 – Aggregate Interconnected DER Capacity and Load at 115kV Interchange

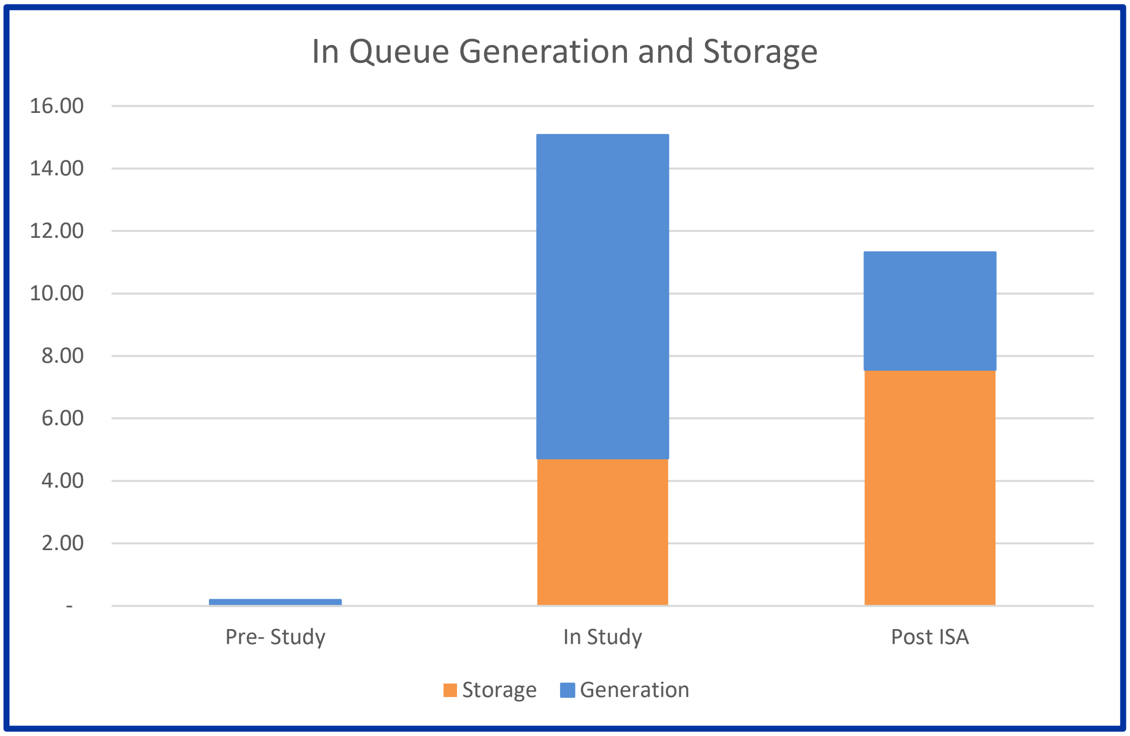
The table below lists the number of DERs interconnected on the Unitil electric system listed by type of DER.[12]

Type of DER	No. of Facilities	Nameplate Capacity (MW)
Gas	4	0.4
Solar	3,137	50.1
Solar + Storage	25	1.2
Storage - Battery	1	2.0
Wood	1	18.0
Total	3,168	71.6

Table 10 – DER Connected to Electric System

In addition to the amount of DER interconnected to the electric distribution system listed above, Unitil has approximately 15% more DER that it is in the process of interconnecting. The chart below lists the capacity of generation and storage that is in queue for interconnection. The status is split between pre-study, in-study, and post ISA. Applications listed as "Post ISA" consists of applications that have been approved for installation and are pending customer payment or approval to proceed, pending material delivery, and in construction.

[12] Data taken from Appendix 1 of the Company's 2022 Grid Modernization Annual Report.



	Pre- Study	In Study	Post ISA
Storage	-	4.72	7.56
Generation	0.19	10.35	3.75

Figure 12 – Generation and Storage Applications in Queue (MW)

The table below shows the DER hosting capacity of each distribution substation on the Unitil system. The Hosting Capacity is the amount of net capacity the transformer has to allow generation to flow in the reverse direction. This analysis compares 30% of the peak load to the aggregate DER capacity.

Substation	Total Installed Generation (kVA)	DER Hosting Capacity (kVA)
Beech Street	10,057	15,200
Canton Street 13.8 kV	1,343	13,900
Canton Street 4 kV	625	2,969
Lunenburg	11,284	2,300
Pleasant Street	13,838	3,000
Princeton Road	8,080	14,700
River Street	11,018	4,000
Sawyer Passway	5,571	15,900
Summer Street	3,638	35,500
Townsend	4,584	8,900
West Townsend	7,314	5,600
Total System	**77,352**	**46,300**[13]

Table 11 - DER Hosting Capacity (as of 6/1/23)

Power generation DER has created challenges to the operation and planning of the distribution system where, due to the aggregate of the DER, power can now flow in both directions. Planning of system capacity must now be analyzed during peak load times as well as light load and high generation times. In addition to capacity analysis, the operation of the distribution system equipment must be considered to ensure the equipment will operate correctly during reverse power flow. Specifically, protective devices and voltage regulating devices need to be designed to operate correctly in both directions.

Electrical Energy Storage System ("ESS") DER installations introduce the same challenges as aggregate for each single installation. A battery acts as a positive load and the negative load at any given time. Without utility control or constraint of the battery, the system must be planned to have the capacity for the battery to charge at full rating (positive load), or discharge at full rating (negative load), at any time of the day. Because the transmission system has different capacity needs than the distribution system, a battery operating for transmission markets, may cause capacity constraints, in both directions, on the distribution system. For this reason, the Company does not assume a particular schedule for the operation of a battery as part of its ESS assumptions.

[13] Total System Hosting Capacity is constrained at the 115/69 kV substation.

Presently the Company plans needed system capacity at the worst case. When analyzing the impact of a proposed storage facility, the rated discharge capacity of the ESS is treated as generation and analyzed at light load times, and the rated charging capacity is studied as load and added to the existing peak load of the circuit. By analyzing the ESS in this way, the operation of the ESS is not constrained to specific times or markets. However, the modeled hosting capacity limit is a fixed level for all hours of the day based on the most limiting constraint.

The variability of solar and ESS can create real-time power quality and reliability concerns in the operation of the distribution system. Without active central control of the facilities the DER output is limited to a fixed limit level, that may not match the time of peak output of the facility. In order to operate the electric system to its fullest capability, central active control of these facilities, is necessary. By being able to curtail the output of the DER facilities at certain times and control the charge and discharge time of ESS, the DER facilities can be allowed to operate at a higher output, more closely matching the hosting capacity profile of the circuit.

Included in the Company's ADMS project is the future plan to incorporate real-time monitoring and control of the output of DER. As part of the DERMS effort of the ADMS project, the Company plans to control the DER. The Company is also monitoring progress made with flexible interconnections and active resource integration to determine how these approaches can be implemented within our service territory.

4.1.6 Grid Services

The Company's demand response program is designed to reduce load at the time of system peak in an attempt to defer capital investment. There are currently 157 customers (154 residential and three C&I), who participate in the Company's demand response program. The accounts for load reductions in the amount of 178 kW,[14] at the time of system peak.

4.1.7 Capacity Deficiency

Currently, the Unitil system loading peaks in the summer months. In order to operate the electric system in a safe and reliable manner, it is important to ensure the loading on any piece of equipment does not exceed the rated capacity of the equipment. For that reason, Unitil calculates summer and winter thermal ratings for each type of equipment and forecasts the loading on all circuits and substations. Thermal ratings of each load-carrying element in the

[14] In 2022, the residential customers saved 99kW and the commercial and industrial customers saved 79kW.

system are determined in order to obtain maximum use of the equipment. The same rating methodologies are used for sub-transmission, substation and distribution equipment. The thermal ratings of each modeled system element reflect the most limiting series equipment within that element (including related station equipment such as buses, circuit breakers, and switches).

In its annual planning process, Unitil analyzes the expected amount of load and compares it to the equipment ratings per its distribution and system planning criteria. Presently Unitil does not have any loading constraints through 2023. Future expected constraints are discussed in Section 6. The tables below list the summer rating of substation transformer and distribution circuit with the forecasted peak load for 2024.

Substation Transformer	Overall Rating Normal (kVA)	LTE (kVA)	Projected 2024 Peak Load (kVA)
Beech St.	25,470	26,880	14,158
Canton St. T1	14,000	14,000	4,540
Canton St. T2	4,060	4,220	2,011
Lunenburg	11,989	12,670	11,882
Pleasant St.	14,000	14,000	9,767
Princeton Rd T2	23,200	24,130	7,880
Princeton Rd T3	23,200	24,130	18,515
River St. 13.8 kV	16,240	16,890	6,705
Sawyer Passway T1	21,225	22,946	5,421
Sawyer Passway T2	21,225	22,946	5,421
Summer St.	28,683	28,683	17,369
Townsend	12,340	12,700	10,175
W. Townsend	10,756	10,756	7,544

Table 12 – Substation Transformer Loading Constraints

Distribution Circuit	Overall Rating		Projected 2024 Peak Load (kVA)
	Normal (kVA)	LTE (kVA)	
01W01	8,916	9,561	4,724
01W02	8,916	9,561	3,015
01W04	9,561	9,561	3,420
01W06	8,916	9,561	3,000
11W11	12,692	13,385	4,540
11H10	2,017	2,017	1,076
11H11	2,017	2,017	1,004
30W30	9,198	9,943	7,260
30W31	10,188	11,014	4,621
20W22	8,916	10,780	1,905
31W34	11,674	12,620	2,406
31W37	12,692	14,341	4,245
31W38	12,692	14,341	3,116
50W53	13,584	14,686	7,880
50W51	11,886	12,850	4,602
50W55	8,066	8,720	5,397
50W56	8,490	9,178	8,516
25W29	11,951	11,951	3,000
25W27	9,561	9,561	2,586
25W28	9,561	9,561	1,601
22W17	8,533	8,533	0
22W2	3,585	3,585	761
22W1	9,322	9,322	5,157
22W3	3,608	3,705	825
22W8	8,490	8,533	616
22W10	9,322	9,322	1,905
22W11	8,490	8,533	1,578
40W38	7,673	9,274	2,350
40W39	9,198	9,561	5,156
40W40	9,561	9,561	8,196
40W42	9,561	9,561	3,830
15W15	8,844	9,561	4,175
15W16	8,844	9,561	5,390
15W17	8,844	9,561	1,666
1341	9,728	10,517	3,598
35W36	6,282	7,328	3,598
39W18	12,692	13,768	4,177
39W19	7,641	8,261	3,367

Table 13 – Distribution Circuit Loading Constraints

4.1.8 Aging infrastructure

While upgrading portions of the distribution system for increased capacity needs is required, in order to continue to provide safe and reliable service and transition to a decarbonized future, replacement and upgrade of the existing aging infrastructure is also necessary. The cost of upgrading this infrastructure will be included as normal base rate spending and is not included in the ESMP proposed spending.

4.1.8.1 Substation Equipment

The main substation equipment consists of power transformers and breakers. Because a substation is the supply to multiple distribution feeders, a failure at the substation affects many more customers than a failure on a feeder. Presently there are 78 breakers/reclosers and 15 power transformers installed in the substations.

The average age of the Protection devices (breaker and reclosers) is 23.5 years. The age of most breakers is the year the substation was constructed or a major project was implemented to upgrade the substation. The chart below displays the ages of the existing breakers and Reclosers. The chart below displays the average age at each substation.

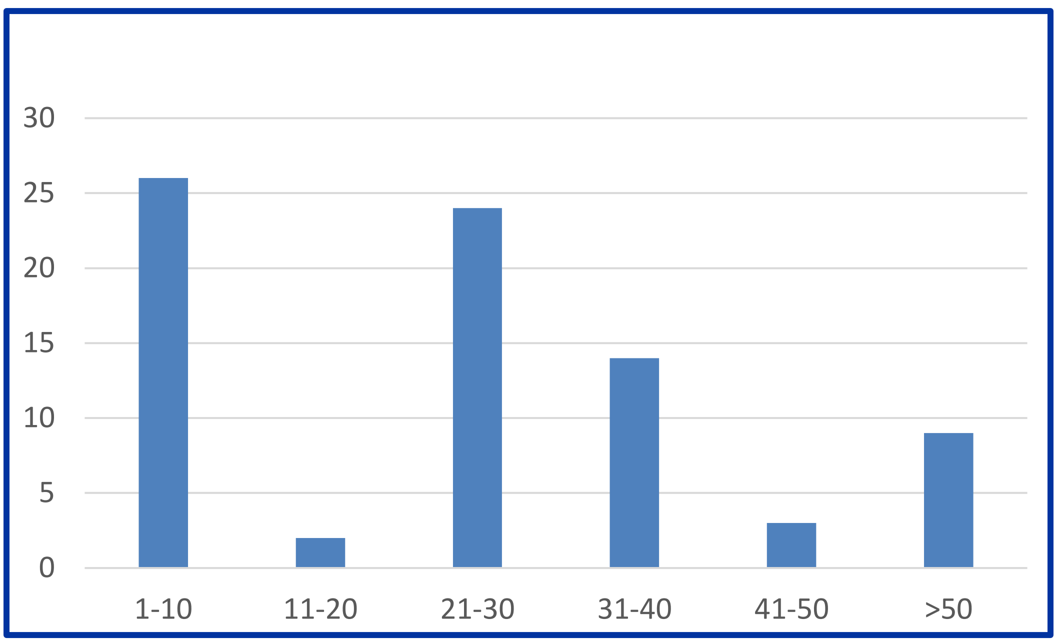


Figure 13 – Substation Breaker/Recloser Age

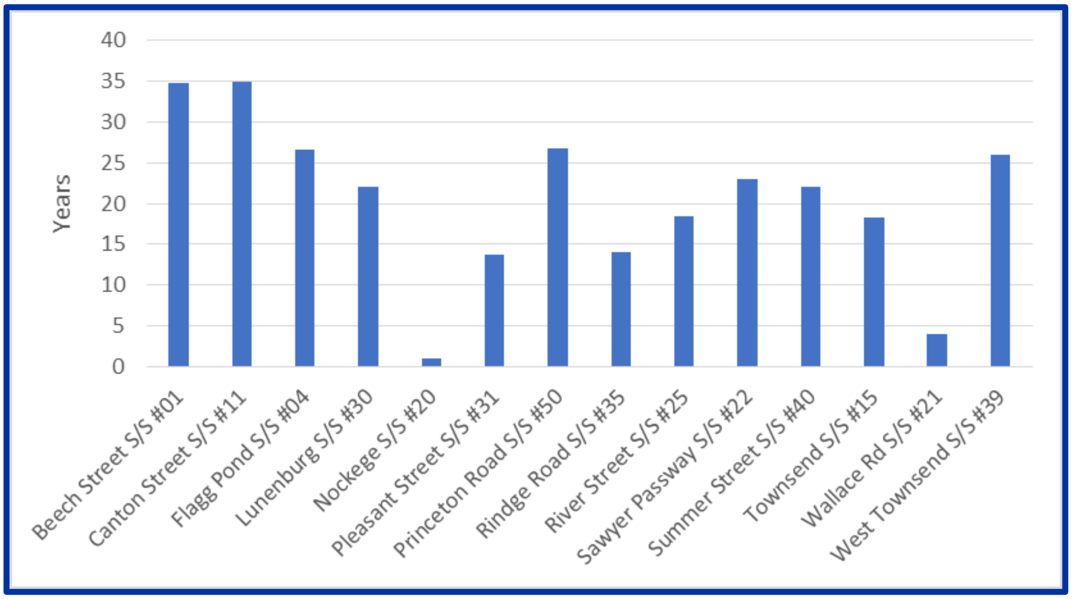


Figure 14 – Breaker/Recloser Average Age per Substation

Substation transformers are maintained periodically per the Company's maintenance policies. In addition, each year an oil sample is withdrawn from every transformer and analyzed to determine the health of the transformer. The loading of the transformers are also monitored to ensure they are not loaded above the specific ratings calculated for the particular transformer. Even with these practices, the condition of a transformer can degrade due to age and through currents it experiences from external system events. The Company normally replaces transformers because of capacity needs or failure and does not replace transformers due to age alone.

The substation transformer ages are displayed in the Chart below.

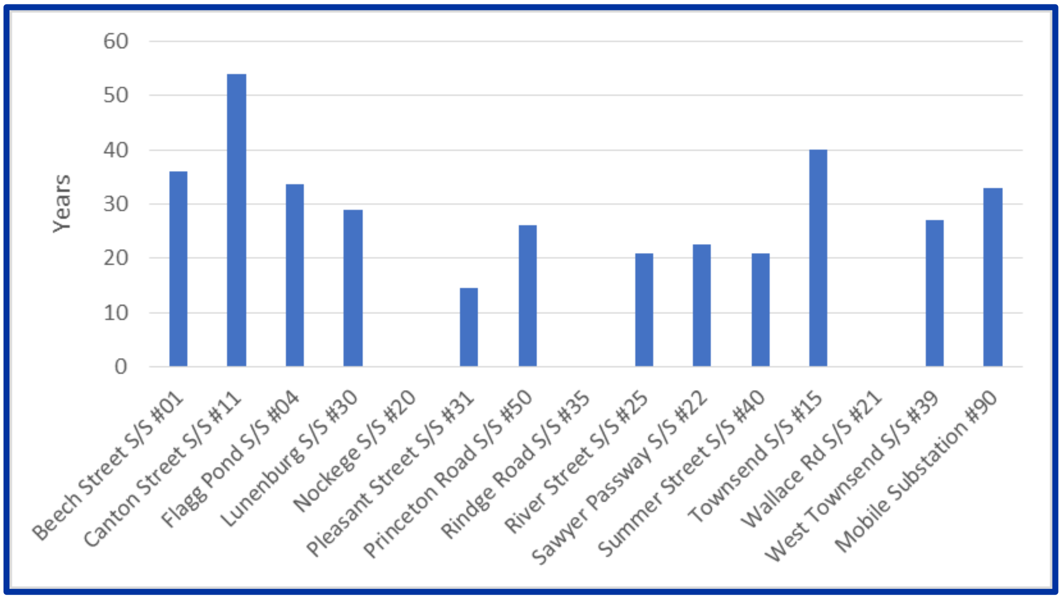


Figure 15 – Substation Transformer Ages

4.1.8.2 Distribution equipment

As described above, the main equipment installed on the distribution system includes poles, voltage regulators, reclosers, and distribution transformers.

Distribution Poles: Poles are replaced as needed due to condition or need to larger poles due to a construction project. There are 19,136 distribution poles on the Unitil system. Each year 10% of the poles are conditionally tested. On average 3% - 4% of the poles tested require replacement.

Voltage Regulators (regulators): There are 83 Voltage regulators currently installed in the distribution system. Voltage regulators are normally only replaced with larger units due to loading constraints. New regulators are being installed on the system as part of the VVO Grid Modernization project. The average age of the voltage regulators on the distribution system is 8 years old.

Capacitor Banks: In the past, capacitor banks were installed for voltage support as well as power factor support. There are 46 capacitor banks on the distribution system currently. Capacitor banks are being replaced for different size units and additional capacitor banks are being installed as part of the VVO Grid Modernization project. The average age of the capacitor banks on the system is greater than 15 years.

Reclosers: The older style reclosers on the distribution system do not have the advanced functionality that microprocessor recloser offer. As new reclosers are installed on the main-line distribution circuit, a microprocessor type recloser is installed with SCADA functionality. Currently there are a total of 64 reclosers on the distribution circuits.

Transformers: There are currently a total of 6,619 transformers on the distribution system. Traditionally Distribution transformers. The chart below details the ages of all the distribution transformers installed.

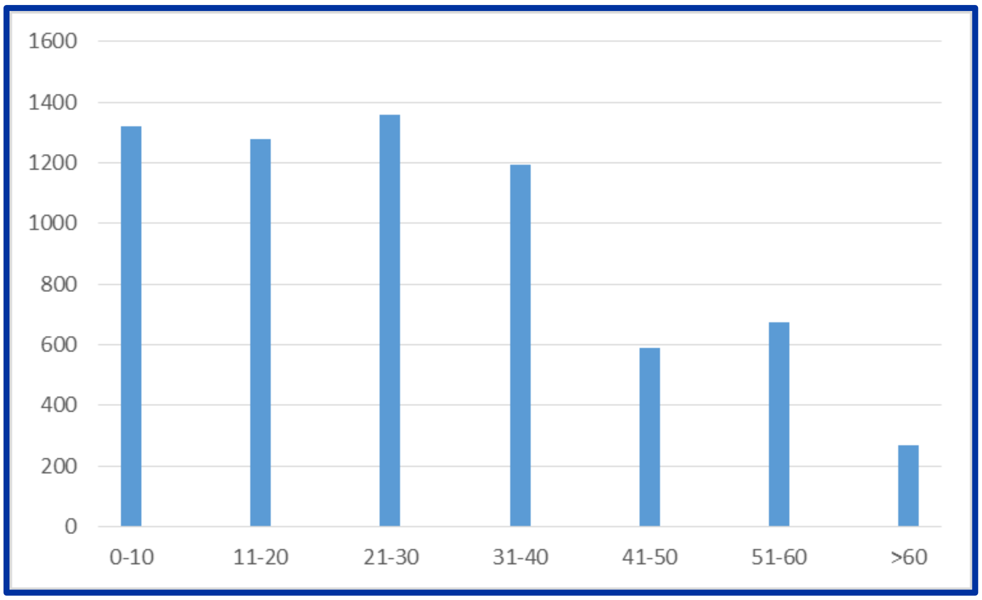


Figure 16 – Distribution Transformer Ages

4.1.9 Reliability and resilience

Reliability planning is conducted by Operations and Engineering staff on an ongoing basis. Projects and programs are designed and implemented to: 1) eliminate outages from occurring; or 2) minimize the impact of an outage by reducing the number of customers affected and/or the duration of time they are affected. The various types of reliability planning are identified below.

Daily – Unitil Operations and Engineering personnel review every sustained outage on a daily basis. This review focuses on system improvements that could be made in order to prevent that outage from reoccurring or other resiliency measures to reduce the size or duration of the outage. Typically, this review results in protection or construction modifications or targeted out of cycle trimming activities.

Weekly – Internal reports on overall company and individual operating center reliability performance compared to annual goals and past history are developed on a weekly basis. This review is used to track the current year reliability and resiliency performance and benchmark it against company goals and historical performance.

Monthly – On a monthly basis, the Company summarizes the significant outages – outages that account for 75,000 customer-minutes of interruption or more, that occurred in each of the operating companies over the past month. The analysis also reports on devices that have experienced multiple outages over a specific period of time and also reports on outages caused by failures of Company equipment. The goal of this reporting is to identify trends and potential causes for the trends and initiate system improvements to address those trends.

System Event Report ("SER") – At the discretion of the Company's executive team, any outage can have an SER report completed. A SER is a root cause analysis conducted by Operations and Engineering. The goal is to identify ways that the outage could either be avoided or the response shortened in the future. Typically, a SER recommends action items that are assigned and completed.

Annual – The Company conducts analysis on an annual basis that is focused upon the overall reliability and resilience performance of the system for a twelve-month period. The reports evaluate individual circuit performance over the same time period. These reports are developed per Unitil's Reliability Analysis Guideline and include:

- Analysis of the ten worst outages that occurred over the timeframe along with their associated impact to the System Average Interruption Duration Index ("SAIDI") and the System Average Interruption Frequency Index ("SAIFI").
- Analysis of the effect of sub-transmission and substation outages on circuit performance.
- Analysis of the worst performing distribution circuits over the reporting period
- Analysis of the major causes of sustained interruptions.
- Analysis of performance issues on specific circuits as well as recommendations for improvement
- Analysis of equipment failures to identify trends and provide recommendations when necessary.
- Analysis of areas with multiple tree related outages for consideration for additional tree trimming.

- Analysis of devices that have operated on more than three occasions over the timeframe.

Reliability improvement projects are designed and estimated. Each of the projects is compared based upon a cost per saved customer-minute and saved customer-interruption basis. These projects are submitted for capital budget consideration.

The reliability planning process described above has proven very successful. The historical reliability performance for the system is outlined below.

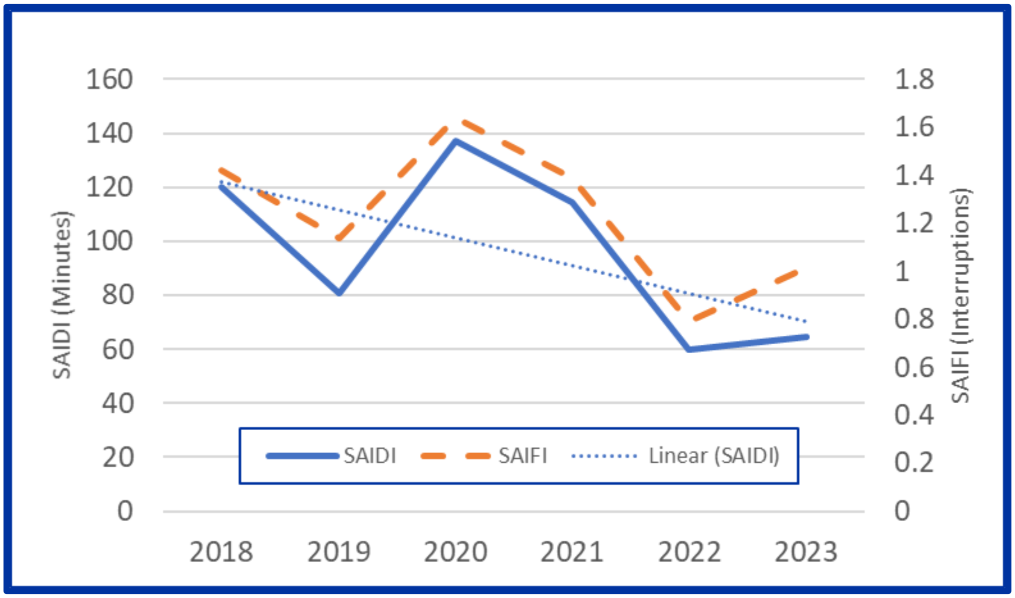


Figure 17 – Reliability Performance

The chart above displays annual SAIDI and SAIFI using Department-exclusionary criteria. The 2022 reliability performance was the best performance in over 25 years. The 2023 system SAIDI of 64.6 minutes is roughly 25% lower than the ten-year average of 86.1 minutes. The system SAIFI for 2022 was 0.79 interruptions which was the best performance in over 25 years. The system 2023 SAIFI of 1.016 interruptions is approximately 17% lower than the ten-year average of 1.22 interruptions.

The Company's vegetation management program (including its cycle pruning and Storm Resiliency Program) has a large impact on the reliability performance of the Company. The Company is experiencing better performance during both blue sky as well as major outage situations. The vegetation management program is resulting in less damage during storms allowing the Company to consistently complete restoration ahead of neighboring utilities and send line resources to assist others with restoration. The Company continues to evaluate the program for improvements where practical.

4.1.10 Siting and permitting

The substations in the Unitil territory are situated on land owned by the Company, while the transmission and sub-transmission lines are situated on land owned and/or easements on private property. When new substations or (sub-)transmission lines are required to be constructed, the availability of land is researched and landowners are contacted regarding the option of purchasing, or obtaining an easement on, the required land. The Commonwealth's siting and permitting process for energy facilities is specified in G.L. c 164, section 69J. Local municipal permitting processes may vary from town-to-town. The Company has not been required recently to implement the siting and permitting process. However, the need for land rights for new substations and sub-transmission lines is expected in the very near future. The Company expects to face siting and permitting challenges similar to those of all utilities in the Commonwealth as described in Section 7.3.

The figure below displays the location of the existing substations and 69kV transmission and sub-transmission lines with the Environmental Justice Communities. This map also includes the approximate location of the new (South Lunenburg) substation proposed to be constructed in 2030 and connected to National Grid's 115kV line(s).

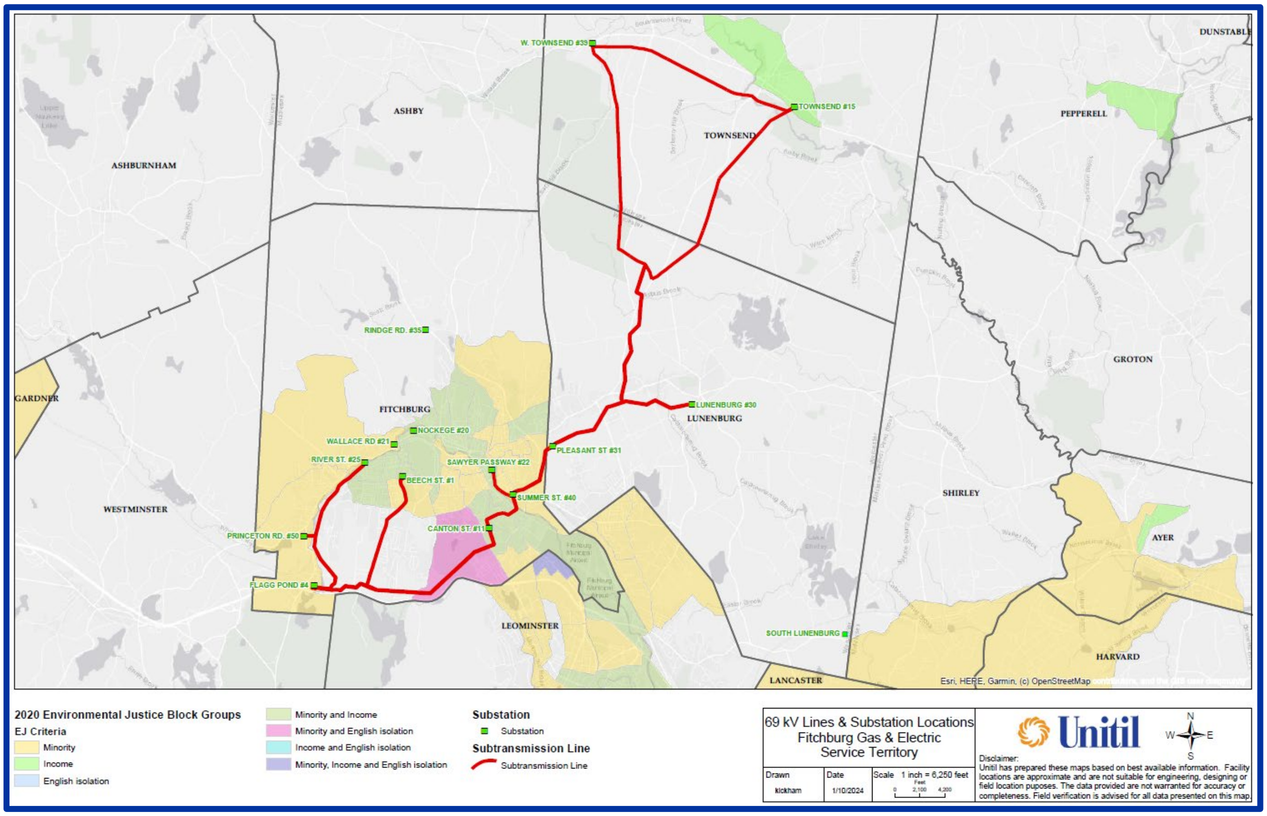


Figure 18 - Unitil 69 kV lines and Substation Location Map

4.2 TECHNOLOGY PLATFORMS THAT WE HAVE IN PLACE TODAY

The Company has been an early adopter of grid technology. The Company implemented AMI for all customer over 15 years ago. The Company first developed its GIS system over 20 years ago and continues to improve on its content and accuracy. Effective technology and secure data sharing is crucial to operating a transparent and open energy system. Customers and other users want to make informed decisions on their energy needs. Developers, meanwhile, need clear rules for how to interconnect renewable energy projects as well as an understanding of where interconnections would maximize the value to the system. The figure below demonstrates the Company's existing technology which it continues to make improvements to through this plan.

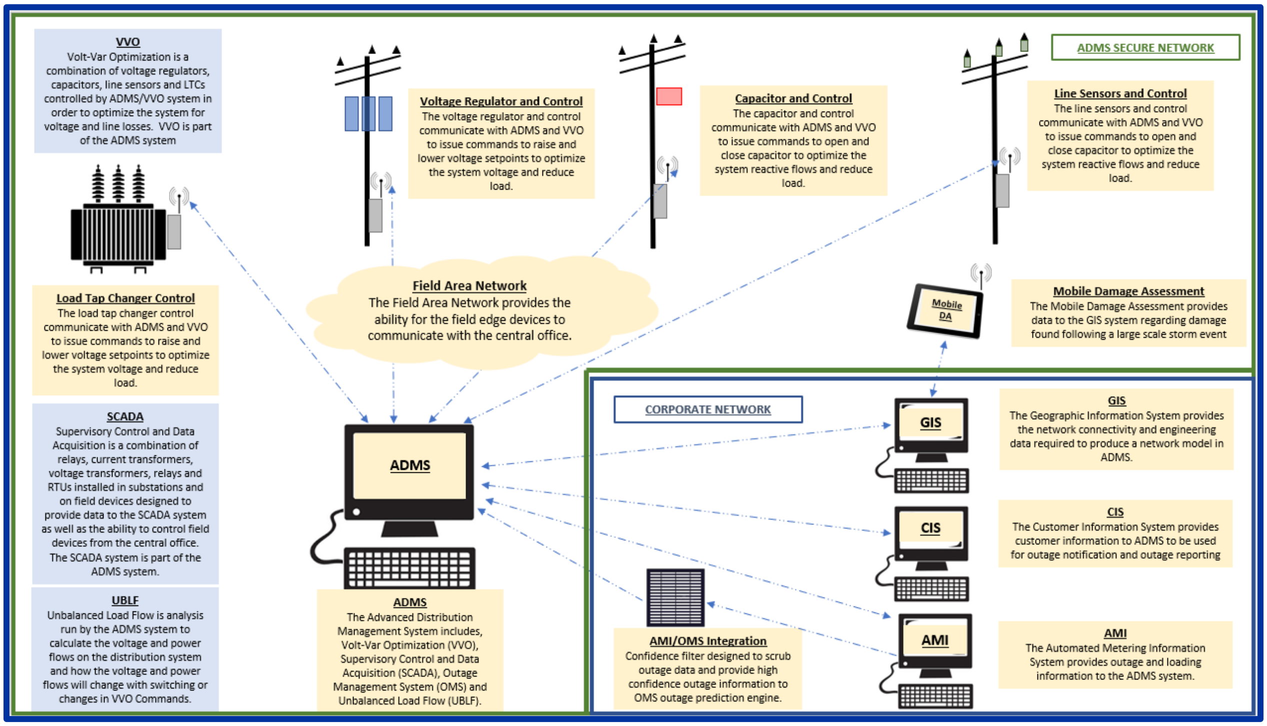


Figure 19 – Existing Technology

4.2.1 Geographical Information System ("GIS")

GIS is an asset database and connectivity model of all distribution assets on the Unitil electric and gas systems. Unitil uses ESRI software to manage and maintain geospatial records for both our gas and electric assets. The models of the electric distribution system provide information of field installed assets and serve as tools for system planning, DER hosting Capacity maps, OMS, and ADMS.

4.2.2 Supervisory Control and Data Acquisition ("SCADA")

SCADA is a system of software and hardware elements that allows an organization to:

- Remotely control assets such as substation circuit breakers, distribution reclosers, Capacitor banks, and voltage regulation equipment.
- Monitor and record real-time data such as voltage levels and power flow
- Trigger alarms based on real-time data and programmed trigger levels.
- Archive data for later study, such as event analysis and historic trending to support forecasting and planning.

SCADA systems in the electric power industry provide a real-time interface between centrally located personnel and systems, such as a dispatch center or OMS and ADMS systems located at a corporate hub, and the remote devices they monitor and control, such as substation transformers, circuit breakers, line switches, capacitor banks, voltage regulators

The architecture of a traditional SCADA architecture includes a distinct remote terminal unit ("RTU") as the on-site interface between the remote SCADA master and the field devices and instrumentation at that site. However, with the advent of microprocessor-based devices and instrumentation, the traditional RTU functions are sometimes incorporated directly into those products, forgoing the need for an actual standalone RTU.

Currently the Company has SCADA commissioned at twelve substations, including the circuit source devices and other devices in the substation. In addition, there is SCADA commissioned at various distribution devices on the feeders outside the substations.

As part of the Company's Grid Modernization Plan, it is expanding SCADA functionality on the devices as well as the number of devices with SCADA functionality.

4.2.3 Advanced Meter Infrastructure ("AMI")

AMI is a system of meters and central communications to allow advanced metering functions and measurements of individual revenue meters. The Company implemented an AMI system across its service territories over 15 years ago. The Company is in the process of replacing its existing system as it has reached the end of its useful life and the vendor is discontinuing support of this technology. As part of its current Grid Modernization Plan, the Company will enhance the integration to provide improved ability for all AMI meters to communicate with Unitil's OMS. This enhanced data will be used in the OMS outage engine to help enhance outage predictions, including which device has isolated the fault and what customers have been restored.

The Company's AMI system provides information on outages for every meter on the Company's system. This project is designed to enhance 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.

The Company's OMS system relies on customer outage calls processed by the interactive voice response ("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 the Company when they are out of power). This small percentage of customer notifications may lead to an erroneous outage location and extend, or delay, the field troubleshooting process.

The Company'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 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), the Company 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).

4.2.4 Outage Management System ("OMS")

The OMS is a computer model of the distribution system including the connectivity of the distribution circuits. The source of this model is provided by the GIS system. The OMS system communicates with the IVR system to receive outage calls from customers. The OMS system identifies the location of the outage using information from the Customer Information System ("CIS") and uses the connectivity model of the system to "predict" the device that has opened causing the outage. When the outage is confirmed, the OMS system calculates the number of customers affected. The OMS system is a tool to help prioritize restoration, manage crew resources, and report outage information.

4.2.5 Volt/VAr Optimization ("VVO")

Customers' demand and system losses can be reduced by adjusting the system power factor and lowering system voltage such more of the power flowing on the system is usable to the customer. This is performed by adding voltage regulation and capacitor banks to the system and controlling them as well as existing transformer load tap changers ("LTCs") with more precise bandwidth through a central controller. The central controller receives real-time measurements throughout the system through the SCADA system and makes decisions of how to adjust the system voltage and power factor. It then sends control signals to the VVO equipment through the SCADA system to adjust the system voltage and power factor.

4.2.5.1 Description of Work Completed

The Company is currently installing VVO equipment on multiple distribution circuits and substations through the 2022-2025 Grid Modernization Plan. Currently VVO equipment is commissioned on seven distribution circuits emanating from two substations. By 2025 it is planned to have eleven circuits and four substations commissioned. Eventually all circuits will be included in the VVO plan.

4.2.6 Advanced Distribution Management System ("ADMS")

The Company is currently implementing an ADMS through its Grid Modernization Plan. The Company manages its distribution system without much control or visibility past the distribution substations and does not have real-time visibility into the vast majority of the distribution resources connected to the network. Limited tools are available to monitor and control the influx of intermittent renewable resources which can cause two-way power flow concerns. These resources have a substantial impact on reliable operation of the system. This mode of operation is not sustainable.

This project will consist of upgrading the Company's current OMS to an ADMS that will support VVO and unbalanced load 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, and OMS will be enhanced to provide the necessary technical information for ADMS to perform the functions described above.

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 integration of outside data sources such as real-time weather and VVO. The ADMS will provide the visibility and control required to operate the advanced grid in a safe and reliable manner. The ADMS will also provide valuable information during outage events and enhance situational awareness resulting in shorter outage durations.

The Company ADMS system is being 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
- Crew assignments
- Engineering based load flow and circuit analysis tools
- Hardware, software, and training
- Hot standby fault recovery

4.2.7 Power Quality Monitoring

At key substations the Company has installed meters that can be queried remotely to download power quality data, so that on a complaint by a customer of poor power quality or voltage disturbances, the Engineering Department can investigate the particular disturbance and recommend potential solutions. In addition to the meters installed at substations, on requests, the Metering Department installs local power quality meters temporarily. The meters are normally put in-service for approximately a week and the data is then downloaded and provided to the Engineering Department for analysis.

5 5- AND 10-YEAR ELECTRIC DEMAND FORECAST

This section describes the approach and assumption to developing the 5-year and 10-year demand forecast. The demand forecast is used to determine where system constraints may exist at future loading levels.

5.1 5- AND 10-YEAR ELECTRIC DEMAND FORECAST AT THE EDC TERRITORY LEVEL

Load forecasting is completed on an annual basis. The annual process ensures that the forecasts are informed by the most recent forecasts for energy efficiency, adoption rates for EVs and heat pumps, new large loads, adoption of DERs including solar and storage and changes in building codes or average energy usage.

The electric distribution companies in Massachusetts (Eversource, National Grid, and Unitil) together have reviewed and compared assumptions for the respective five- and ten-year electric demand forecast across the Commonwealth. The methodologies employed by each individual EDC are aligned for the baseload econometric forecast, design weather conditions, and DERs. The table below provides a high-level comparison of the methodologies used by the EDCs. More detail specific to each EDC is provided in Section 5 of each respective Plan.

The table below provides a summary a comparison across EDCs.

<table>
<tr><th>Category</th><th>National Grid</th><th>Eversource</th><th>Unitil</th></tr>
<tr><td>Weather Data</td><td colspan="3">Utilize more than a decade of historical weather data to develop the design weather – the 90th percentile – and use it as the primary planning case. The specific weather stations used are region dependent.</td></tr>
<tr><td>Forecasting Model – Baseload</td><td>Econometric forecast model for the baseload.</td><td>Econometric forecast model for the baseload.</td><td>Projects recent historic growth forward for baseload.</td></tr>
<tr><td>DER Forecasts</td><td colspan="3">Each DER is independently forecasted considering their current market trend, policies, programs, and State decarbonization pathways.</td></tr>
</table>

Regional Forecasts	Produce the forecasts at the jurisdiction level and allocate to more granular geospatial area based on regional characteristics.		
Energy Efficiency	Near term: Company three-year plan approved by the Department. Long-term: continued growth reflecting market saturation.	Company three-year plan approved by the Department continues to 2033.	Near term: Company three-year plan approved by the Department. Long-term: continued growth at similar rates.
Demand Response	Continuation of Company's DR programs with growth.	Not considered	Not considered
EV Adoption Forecasts	LDEV adoptions based on the Commonwealth's adoption of California's Advanced Clean Car Act II Regulation. MDEV and HDEV and E-buses based on Commonwealth's adoption of California's Advanced Clean Truck Act.	Following a trajectory that meets the 2050 MA CECP.	Near-term: Follow NE-ISO assumptions. Long-term: Align with Commonwealth goal under "All Options" Scenario.
Heat Pump Adoptions	Near-term: three-year plan approved by the Department. Long-term: following a trajectory that meets the CECP "Phased" electrification scenario.	Following a trajectory that meets the "All Options" electrification scenario.	Near-term: three-year plan approved by the Department. Long-term: following a trajectory that meets the "All Options" electrification scenario.
Storage	Near term based on interconnection queue and meeting State policy target of 1,000 MW by 2025, with continued growth after.	Near-term: based on interconnection queue. Long-term: Following a trajectory that meets the "High Electrification" scenario	Near-term: based on interconnection queue. Long-term: Following a trajectory that meets the "All Options" scenario.
Solar Adoption	Near-term: based on interconnection queue. Long-term: Following a trajectory that meets the "All Options" scenario.	Near-term: based on interconnection queue Long-term: Following a trajectory that meets the "All Options" scenario.	Near-term: based on interconnection queue. Long-term: Following a trajectory that meets the "All Options" scenario.

Table 14 – EDC Forecasting Assumption Comparison

The table below details the Massachusetts 2050 Benchmark across the EDCs in Base Case:

Technology	State-wide Climate Benchmark	National Grid 2050	Unitil 2050	Eversource 2050	Total Forecast
Solar PV (MW)	23,000 [1]	10,400 [3]	250	9,700	20,350
Energy Storage (MW)	3,000 [1] 5,800 [2]	2500 [3]	60	2,600	5,100
Electric Vehicles	5,400,000 [1]	2,700,000	53,000	2,700,000	5,453,000
Electric Heat Pumps	2,000,000 [1]	1,130,000	21,000	1,100,000	2,251,000

[1] From All Options Scenario

[2] From 2050 CECP Phased Scenario

[3] This is the total solar/storage expected to be in National Grid's territory. Only the portion that is considered "distributed" generation is included in the forecast.

Table 15 – Massachusetts 2050 Benchmark Across Utilities in Base Case

The Company's load forecasting methodology for this evaluation was based on its existing forecasting methodologies for base load, DER, EV and electrification forecasts and the Commonwealth's pathway for decarbonization. The Company established its 2050 portion of the Commonwealth's 2050 CECP "All Options" pathway for decarbonization for various technologies and established these as the approximate 2050 forecast. The Company then used its existing methodology to develop its 5-, 10- and 25-year forecasts.

Technology	State Benchmark	Unitil Scaled Benchmark	Unitil 2050 Forecast
Electric Vehicles	5,400,000	50,734	52,841
Residential Air-Source Heat Pumps	2,000,000	18,790	19,308
Residential Ground-Source Heat Pumps	195,000	1,832	1,826
PV	23,000 MW	216MW	254MW
Energy Storage	5,800 MW	54MW	60MW
Commercial	87%	87%	87% of Company's Gas Customers
Industrial	52%	52%	52% of Company's Gas Customers

Table 16 – Company's Portion of Pathway for Decarbonization - 2050

Aggregate summer and winter demand at the Company's bulk substation, Flagg Pond, is determined based on the system peak load forecasts with a review of expected power flow through (both forward and reverse) directions. The review includes the incorporation of both DER and electrification. In the case of the Flagg Pond, additional Photovoltaic ("PV") adoption/installations has little impact on the reduction of winter or summer peak load as the current penetration of PV served from Flagg Pond substation has shifted the aggregate summer and winter peak demands to hours of the day in which PV facilities are generating minimal amounts of energy (i.e. 7:00PM). Flagg Pond aggregate winter and summer peak demand forecasts are included in the table below. The Company will continue to evaluate these results from year to year for differences. For instance, since 2020, the SMART program has required that all new solar, with limited exceptions, be paired with energy storage and incentivized by the Clean Peak program to export during peak hours.

Year	Winter Forward Powerflow (MW)	Summer Forward Powerflow (MW)
2025	84	98
2026	86	99
2027	89	99
2028	92	100
2029	94	101
2030	98	102
2031	101	103
2032	105	104
2033	109	106
2034	114	108

Table 17 – Flagg Pond Bulk Substation Load Forecast

The latest aggregate winter and summer demand forecasts indicate that the Flagg Pond substation exceed its capacity under N-1 conditions for loss of supply transformer as early as 2034.

In the sections below, the Company provides sensitivity analyses for information purposes only. The Company focuses on its calculated 5- and 10-year forecasts to ensure the reliability and safety of the electric system due to the short-term nature of the forecast and timelines to develop major capital projects. Sensitivity analysis is also provided for the 2035-2050 forecast in Section 8.

5.1.1 Base Peak Load Forecasts (Weather normalized econometric forecast)

The historical basis for the Company's Base Summer Peak Load Forecasts is a series of yearly regression models developed to correlate actual daily loads to a Weighted Temperature-Humidity Index ("WTHI") derived from the average temperature and average dew point temperature of each day and the previous two days. Once a model is established, an estimated peak load can be derived for that season for any value of WTHI. There are two dimensions of variability introduced with this modeling. First is the highest WTHI experienced within a season, which varies with short-term weather trends from one year to another. Second is the model estimate of peak load at any specific WTHI. This estimate has its own variation of possibilities due to the influence of other existent factors not incorporated into the model. These variations are characterized as randomness in making future projections. The probability distribution for annual highest WTHI is assumed to follow the discrete distribution of past historical highest WTHI. The random possibilities of peak load outcomes for any specific WTHI are assumed to follow a standard probability distribution model with a mean centered on the point estimate of the peak load at that WTHI and varying based on its individual standard deviation according to the fit of the seasonal model to the actual historical values.

To establish load projections, a Monte Carlo simulation is run to produce random annual highest WTHI and random peak load estimates at those WTHI from each year's seasonal model that makes up the historical basis. Typically, the more recent, heavily loaded and highest WTHI years are given a higher weighting factor in the analysis than other years. This is done in attempt to put more emphasis on years with historically hot weather and more recent years with more inherent "electrification" technology (DER, EV, etc.) load and generation. This approach is also good at identifying instances where current technology adoption trends (i.e. electric vehicles or heat pumps) may be accelerating. In the case of these forecasts 2020 was weighted two times, 2021 weighted five times and 2022 was weighted ten times years the 2013 to 2019. Each trial in the simulation is projected forward using linear trending. This results in a range of peak load possibilities for each future year assuming linear growth, and varying due to annual highest WTHI possibilities and variability in loads versus WTHI. The likelihood of specific peak load levels occurring in any particular future year can be estimated from an assumed probability distribution using the mean and standard deviation of the trial results for that year. Base Summer Peak Load Forecasts are set at a 90% probability limit. This is intended to roughly equate to a 1-in-10 year likelihood that the forecasted load level will be exceeded.

DERs that are operating during peak load conditions offset system tie point power flows consequently reducing historical system loads. Therefore, the power offset or produced from all known significant DER units must be accounted for in the load forecasts. Unitil adds the output from all known significant DER units to its historical systems tie point flows prior to calculating the load forecasts. These units are then modelled in different dispatch scenarios in the system modelling process.

The Company's Base Winter Peak Load Forecasts are derived from the Base Summer Peak Load Forecasts utilizing the historical percentage difference between the historical average of the three peak days of the previous three years for the summer seasons and the historical average of the three peak days of the previous three years for the winter season.

Hourly interval load forecasts for the peak day are then developed for both the winter and summer seasons. These hourly interval forecasts are derived based on the average hourly interval loads for the three peak days of each season for the previous three years.

The Company utilizes the base forecasts described above as the "baseline" Base Load Forecasts in this review. As part of the Company's sensitivity analysis a "low-rate" or "minimum" and "high-rate" or "maximum" base load forecast is developed utilizing randomized factors based on the baseline Base Load Forecasts. In general, the low-rate forecasts were approximately 2.5% to 5% less than and the high-rate forecasts were between 5% and 10% greater than the baseline Base Load Forecasts.

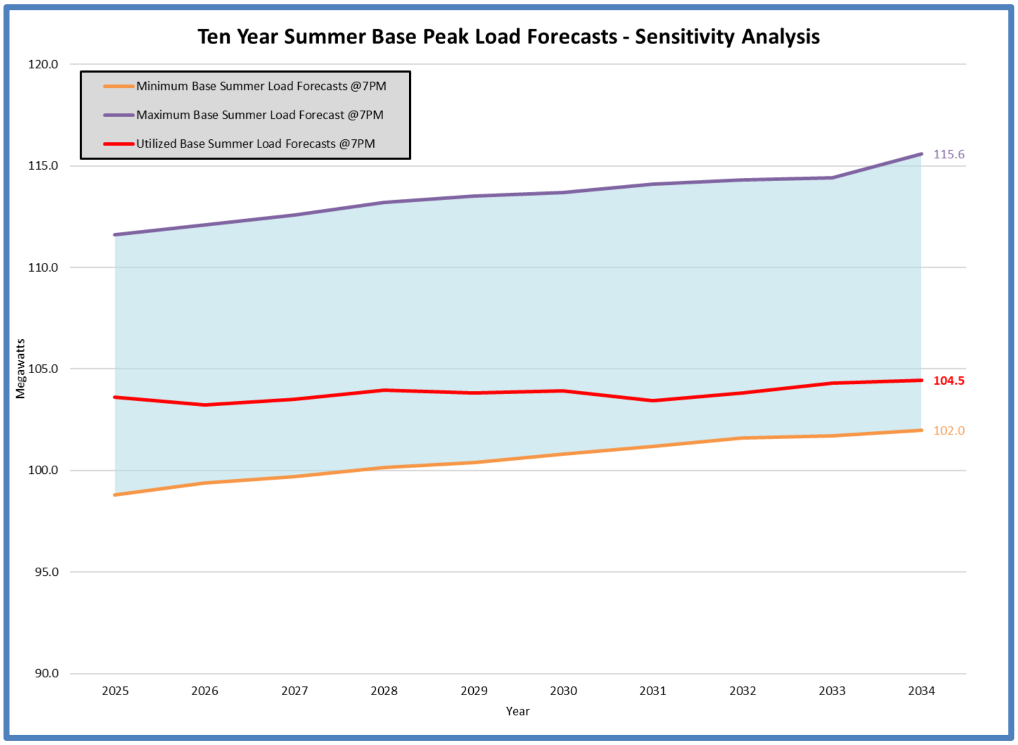


Figure 20 – Ten Year Summer Base Peak Load Forecasts – Sensitivity Analysis

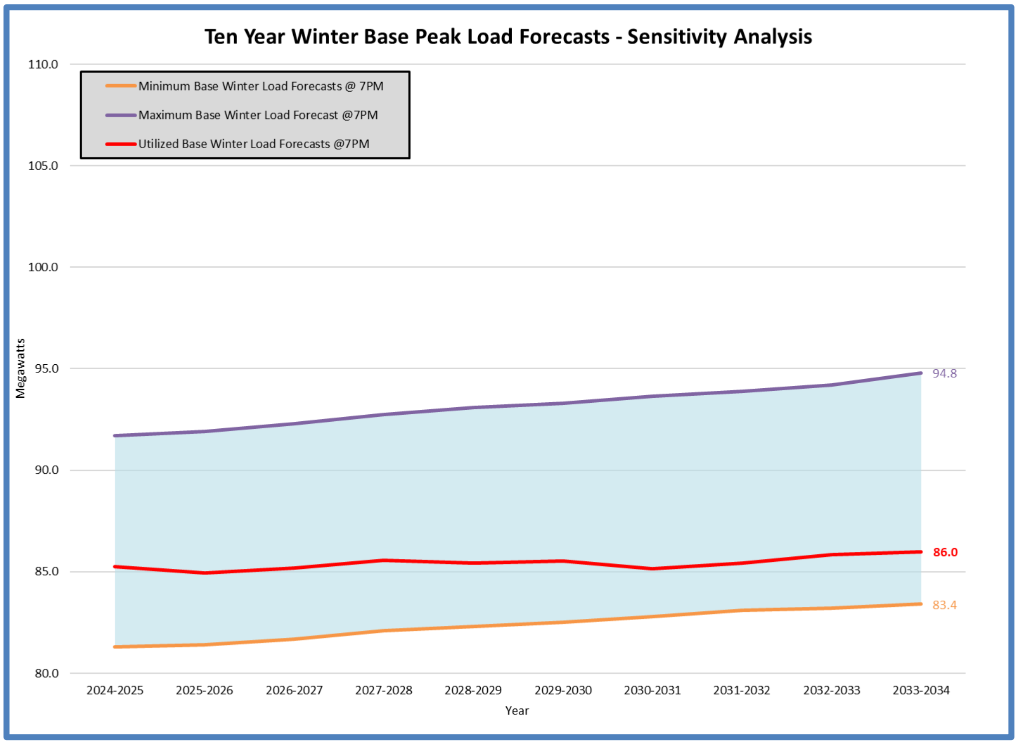


Figure 21 – Ten Year Winter Base Peak Load Forecasts – Sensitivity Analysis

5.1.2 Large Load (step/spot load)

Large loads, also known as "step loads" or "spot loads" are considered load adders to the forecast. Large loads are determined to be those known significant loads that have a material impact on the load forecast. Large loads may be handled in different manners depending on the type of load.

Two large loads were excluded from the weather normalized forecasts and were added into the base forecasts after the weather normalized forecasts were completed. The first is a large customer load (approximately 8.0 MW) served by Princeton Road 50W53 circuit.

The second is a newly proposed customer project located in southern Lunenburg. This load was assumed to be approximately 3.0 MW and was included as a step load adding to the load forecasts.

5.1.3 Energy Efficiency

Energy efficiency is considered a load reducer to the forecast. The Company is a program administrator in the Mass Save Energy Efficiency Plan. The energy efficiency ("EE") programs the Company offers to its customers are developed as part of a comprehensive and collaborative approach to optimizing energy use by electricity and natural gas customers. The Company works collaboratively with the state regulatory agencies and interested stakeholders to develop energy efficiency programs designed to meet state goals. The Company pursues cost effective EE in pursuit of annual energy saving goals established through a robust stakeholder process. The Company's EE programs are informed by nearly two decades of experience working with stakeholders, consultants, our colleagues at the other gas and electric utilities, as well as our customers.

The Company's 2022-2024 Three-Year EE Plan calls for just over $22 million in investment of energy efficiency and electrification measures. Based upon the EE Plan, the expected passive and active energy savings is approximately 0.5 MW.

Past EE efforts and outcomes are imbedded in the historical loading information used for the demand assessment forecast. EE Plan development is handled in a separate proceeding, resulting in three-year funding levels and projected savings. The Company expects these savings to continue into the future, but they are not specifically called out in the forecast as it is difficult to separate historical energy efficiency savings from the historical load data. The Company completes load forecasting on an annual basis and will adjust future annual load forecasts as subsequent EE plans are developed.

5.1.4 DER Growth: Solar PV, Battery Storage, Grid Services

DER is considered a load reducer in the Company's load forecast. Unitil separately develops ten-year DER forecasts on an annual basis. These DER forecasts are established based on the five-year and three-year historical slope of DER capacity growth as well as the overall number of DER facilities and the number of customers served. These forecasts are then incorporated into the Company's peak load forecasts.

To incorporate DER forecasts into the System Load Forecasts the projected incremental DER (DER projection minus the in-service DER) is used to develop hourly DER projections.

Similar to the hourly baseload forecasts normalized hourly peak DER output is calculated using the average hourly DER output of the large DG on the system for the three peak days of the previous three years for both the winter and summer seasons. Each hour of normalized average hourly peak DER output is then multiplied by the projected incremental DER.

The calculated relationship factor between DER with a nameplate capacity of less than 500kW and DER with a nameplate capacity of 500kW or more is utilized to calculate the expected peak output of the incremental forecasted DER for each hour.

Year	Nameplate (MW)	New Impact on Peak (MW)
2025	82.3	-0.6
2026	83.8	-0.8
2027	85.2	-0.9
2028	86.7	-1.1
2029	88.1	-1.2
2030	89.6	-1.4
2031	91.0	-1.5
2032	92.5	-1.7
2033	94.0	0.0
2034	101.1	0.0

Table 18 – Ten Year PV Forecasts – Total Installed

In addition to the DER forecasts described above the Company assumed sufficient "Bulk" ESS would be installed to level the load curve. Hourly dispatch (charge/discharge) were developed based on the forecasted peak day hourly interval data.

Hourly system load forecasts, including PV, EV and electrification was used as a basis for the ESS forecasts. Hourly load above or below the peak day average hourly load was used to determine both the kW peak charge/discharge ESS needs as well as the daily kWh charge/discharge needs.

Assumed charge/discharge schedules were then assumed for both Winter and Summer seasons based on the hourly load curves. Additionally, the Company assumed that 25% of the forecasted ESS would either be unavailable or doing the opposite of what was required at the time (charging when loads would dictate discharging and vice versa).

Year	Nameplate (MW)	Nameplate (MWh)	Impact on Peak (MW)
2025	1.8	10.5	-0.5
2026	3.0	17.5	-0.8
2027	4.2	24.5	-1.1
2028	5.4	31.5	-1.4
2029	6.6	38.5	-1.7
2030	7.8	45.5	-2.0
2031	9.0	52.5	-2.3
2032	10.5	61.3	-2.6
2033	12.0	70.0	-3.0
2034	13.5	78.8	-3.4

Table 19 – Ten Year Bulk ESS Forecasts

The Company then developed various ranges of adoption, both above and below the baseline forecasted amount of both DER and ESS. These various ranges were then incorporated in the Company's overall load forecasting sensitivity analysis. DER and adoptions rates in these scenarios are as high as 15% to 25% above and 10% to 15% below the baseline DER forecasts.

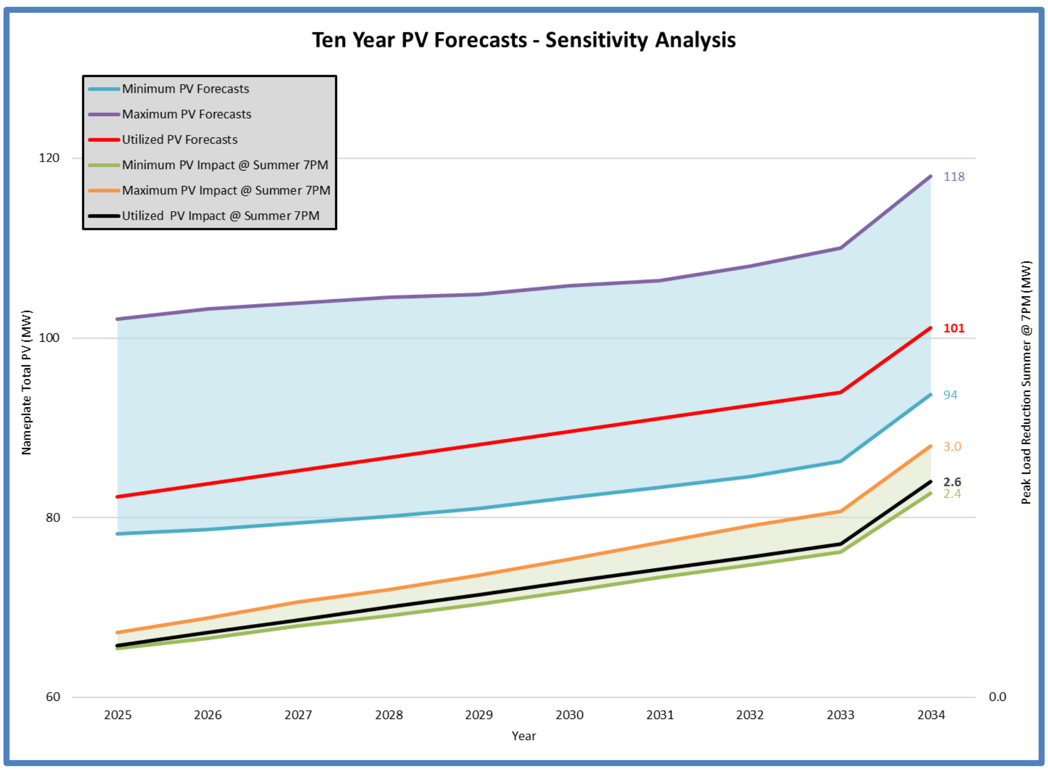


Figure 22 – Ten Year PV Forecasts – Sensitivity Analysis

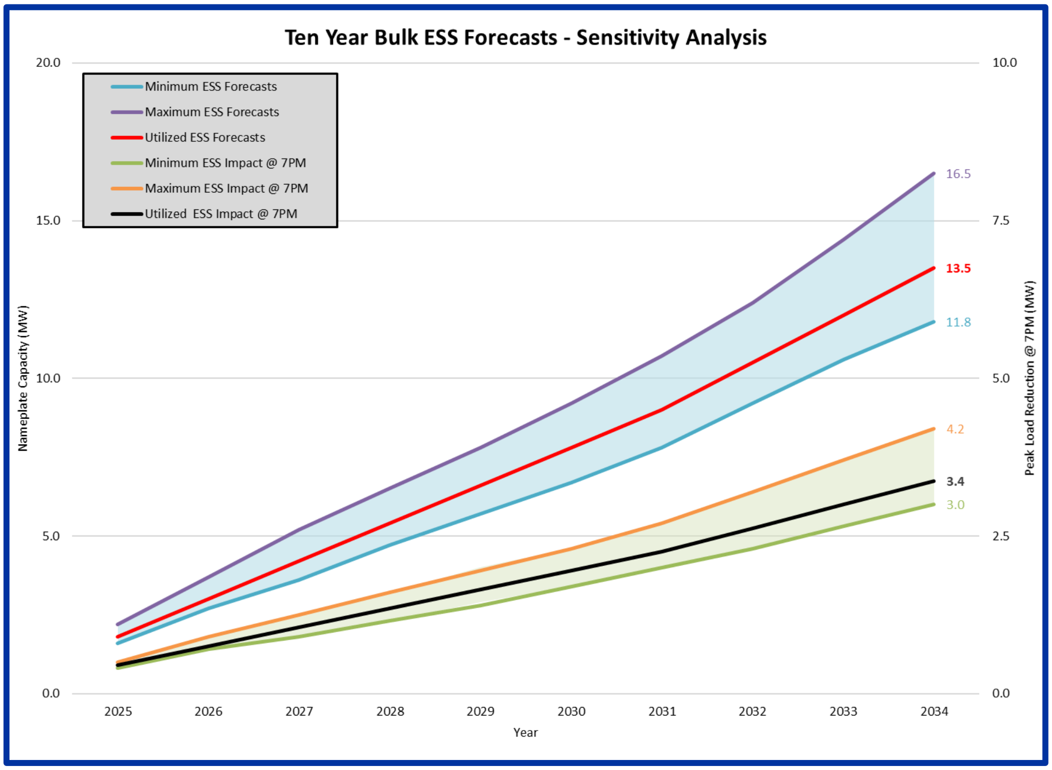


Figure 23 – Ten Year Bulk ESS Forecasts – Sensitivity Analysis

In order for DERs to be considered as an alternative to traditional investments such as transformer capacity additions or reconductoring they need to have the same level of reliability, redundancy and availability as traditional alternatives. In general, traditional investments have a high level of reliability and availability and the EDCs have redundant capacity and spare equipment to reduce exposure of equipment being unavailable. The incorporation of non-EDC owned assets into the Company's planning criteria is something that requires significate planning and consideration to ensure the non-traditional investments are designed with the same level of reliability, redundancy, and availability as traditional alternatives.

There are three primary approaches to optimize DER integration. The first is selecting the correct location which can be optimized with locational analysis. To maximize the electric system benefit DERs not only need to be installed in areas in which hosting capacity is available, but also in areas in which the DERs can provide system value by reducing system constraints. Locational analysis can be used to determine the locational need as well as the locational benefit to the system.

The second possible option is DER curtailment via a defined schedule. These schedules will be established system wide and be modifiable as new DERs are constructed and loads change. It is also expected the need times of DERs and ESS will change by the season and over time making defined schedules difficult to maintain as the nature of the electric system changes.

The third approach is to enable fully dispatchable DERs controlled by the EDC. This will require the implementation of control systems, such as DERMS, and not only require the EDCs to control these assets as needed, but the visibility to their availability and capabilities in real-time will also be required.

In addition to the Company's requirements to evaluate NWAs, it has developed an NWA evaluation tool to assist in determining the size and characteristics of DERs that would be needed to defer or eliminate the need for identified traditional alternatives. This tool utilizes historical load cycles of the equipment in violation and equipment ratings to assist in the determination of NWA requirements.

Another challenge with PV, ESS and electrification is the effect this infrastructure has on the load curve and traditional equipment ratings. In order for ESS to provide system value, they need to provide short term peak load support and longer-term energy reduction. It is anticipated that the ratings of equipment such as transformers that rely on a light load period to provide hours of cooling in a 24-hour load cycle will be reduced as the load curve is flattened over time.

The Company provides more detail in Section 9 on NWA alternatives and ways in which DERs can be deployed to maximize the benefit to the system.

In addition to the discussion above, on October 31, 2023 the Company filed draft Operational Parameters for Energy Storage Systems Tariff, filed pursuant to Chapter 172, Section 72 of the Acts of 2022 ("An Act Driving Clean Energy and Offshore Wind," or the "Act"). Section 72 of the Act directs the Commonwealth's EDCs to file with the Department, on or before October 31, 2023, "at least one electric rate tariff, which addresses operational parameters, to apply to energy storage systems interconnected to their distribution network." The Company worked in collaboration with the other EDCs to solicit stakeholder input and develop a tariff meeting the requirements of the Act, submitted a tariff for the Department's consideration and approval.

The Operational Parameters Tariff sets operational and technical parameters for distribution-connected ESS, including: (1) use of Dispatch Limiting Schedules; (2) limits on ESS capacity based on feeder operating voltage and feeder and substation loading as a percent of their ratings; and (3) DERMS readiness. The Operational Parameters Tariff also addresses rate assignments for standalone ESS that do not participate in the wholesale market. The Company intends to submit a proposal to FERC for a wholesale distribution rate governing rates for ESS that are interconnected to the distribution system and plan to participate in the wholesale market as required by the Act.

The objective behind the Operational Parameters Tariff is to formalize the technical requirements for ESS and to create a sustainable process to enable the Commonwealth's clean energy goals and further development of the ESS market. The Operational Parameters Tariff moves toward interconnection behaviors, designs, and locations that may best support advancement toward state energy targets and will lay the foundation for DERMS implementation. This is a good first step for energy storage systems to be operated in a manner that can be considered as an alternative to traditional investments.

5.1.5 Electric Vehicles

EVs are considered to be a load adder in the load forecast. The Company prepares ten-year EV charging load forecasts that are incorporated into the base system load forecasts. The ISO-NE EV Adoption Forecasts for Massachusetts are used as the basis for the Company's EV load projections. These ISO-NE forecasts, along with ISO-NE EV stock (registered) data, are used to project the number of EVs on the road and ultimately the number of EV chargers within the Company's service territory.

ISO-NE information on the number of EVs currently registered in Massachusetts is used to estimate the current number of EVs in the service territory. Once the number of EVs is determined, the ISO-NE EV Adoption Forecasts are used to project the number of EVs. Two forecasts for each territory are created:

- High Rate – utilizes 100% of the ISO-NE EV Adoption Forecasts
- Baseline Rate – utilizes 67% of the ISO-NE EV Adoption Forecasts

Utilizing the assumptions below, the Company estimates the number of home level 1 and level 2 chargers in Unitil's service territory. EEI projections for the percentages of the total number of each type of level 2 charger allows for the calculation of the estimated number of level 2 public and workplace chargers. Workplace chargers do not include fleet charging. Fleet charging assumptions are included in the DCFC assumptions.

Utilization percentages (percentage of total of each type of units charging) for each hour of the day for home, public (including DC fast chargers) and workplace chargers and the assumed demand for each type of charger is used to calculate the forecasted load due to EV charging for each hour of the day.

Assumptions

The following assumptions were used to calculate Unitil's EV load forecasts:

- Every EV owner will have some form of home EV charging
  - 33% will have Level 1 Chargers
  - 67% will have Level 2 Chargers

  Note: For the purpose of this forecast Level 1 Chargers are assumed to only be utilized as home chargers

- Percent of total Level 2 chargers (based on EEI projections)
  - 78% Home
  - 8% Public
  - 13% Workplace
  - 1% Other

- Demand for each charger type
  - Level 1 Charger – 1.7kW
  - Level 2 Charger – 9.6kW
  - DC Fast Charge Facility – 600kW

- % of Total EV by Type
  - Personal Light Duty – 95.2%
  - Fleet Light Duty – 4.3%
  - Fleet Medium Duty – 0.2%
  - School Bus/Transit – 0.3%

- Number of DC fast charge facilities per forecast type
  - High Rate – 2 DC fast charge facilities per year
  - Baseline – 0.5 DC fast charge facilities per year or 1 facility every two years

- Hourly Utilization Percentages

Hour of Day	Home	Public	Workplace	Hour of Day	Home	Public	Workplace
0:00	75%	25%	5%	12:00	15%	75%	60%
1:00	75%	25%	5%	13:00	15%	60%	60%
2:00	75%	25%	5%	14:00	15%	60%	60%
3:00	75%	25%	5%	15:00	25%	50%	60%
4:00	75%	25%	5%	16:00	30%	40%	50%
5:00	60%	25%	5%	17:00	40%	40%	40%
6:00	50%	35%	5%	18:00	50%	30%	15%
7:00	50%	35%	10%	19:00	60%	30%	10%
8:00	40%	50%	15%	20:00	60%	30%	5%
9:00	30%	60%	60%	21:00	60%	30%	5%
10:00	15%	75%	60%	22:00	75%	30%	5%
11:00	15%	75%	60%	23:00	75%	25%	5%

Table 20 – Hourly EV Utilization

For the purposes of the ten-year system peak load forecasts the Company uses the baseline rate forecasts when incorporating EV charger load forecasts. The Company currently anticipates that EV adoption will continue to be slower than anticipated over the next several years due to penetration of charging infrastructure and until vehicle owners are presented with vehicle replacement decisions. However, as stated previously, the Company completes an annual forecast in an attempt to align with the most up to date information regarding adoption trends and technology.

Year	Forecast (# EVs)	
	High Rate	Baseline
2025	759	426
2026	1,163	607
2027	1,608	788
2028	2,092	970
2029	2,606	1,150
2030	3,138	1,325
2031	3,690	1,497
2032	4,332	1,688
2033	5,286	1,967
2034	6,450	2,291

Table 21 – Ten Year EV Forecasts

Year	Forecast (MW)	
	High Rate	Baseline
2025	3.5	1.9
2026	5.1	2.5
2027	6.9	3.3
2028	8.6	3.9
2029	10.6	4.6
2030	12.7	5.3
2031	14.1	5.7
2032	16.5	6.4
2033	19.2	7.2
2034	23.6	8.7

Table 22 – Ten Year EV Load Forecasts @ 7PM

Year	Forecast (MW)	
	High Rate	Baseline
2025	7.7	3.9
2026	11.1	5.5
2027	14.9	7.0
2028	19.1	8.6
2029	23.5	10.1
2030	28.0	11.6
2031	32.7	13.1
2032	38.2	14.7
2033	46.9	17.4
2034	57.5	20.6

Table 23 – Ten Year EV Nameplate Charger Forecasts

Similar to DER and ESS forecasts the Company develops various ranges of adoption, both above and below the baseline forecasted amount of EV and EV charging load. EV adoption rates in these scenarios are as high as 15% to 25% above and 10% to 15% below the baseline EV forecasts.

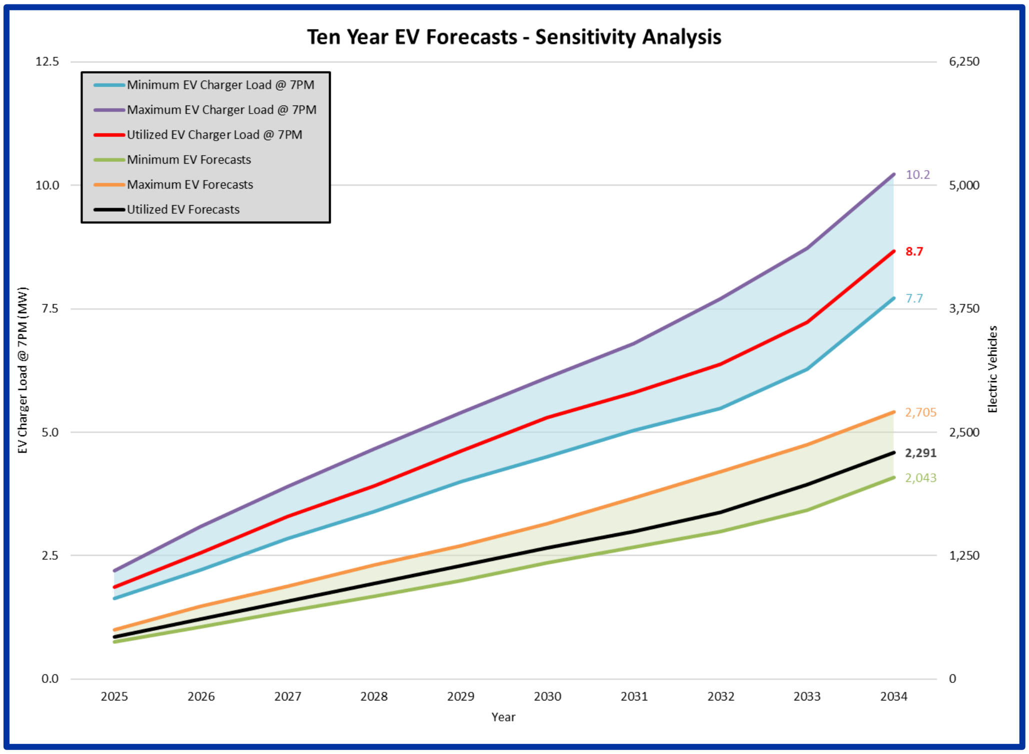


Figure 24 – Ten Year EV Forecasts – Sensitivity Analysis

Vehicle-to-Grid ("V2G"), also referred to as managed charging, is a technology that allows electric vehicles to charge when the electric system has excess capacity and to discharge or provide a source into the electric system when the system may need more capacity. V2G can have the impact of helping the electric system balance more and more renewable energy and EV load. The Company does not have a V2G program at this time. However, a V2G strategy will be required to address the large increases in expected load as EV adoption increases.

At this point, the future EV load forecasts do not include the impacts a V2G program may have on the electric system. The Company will continue to evaluate the most up to date information on V2G technologies as part of its annual forecast and determine the impact V2G may have on the EV load forecasts.

5.1.6 Electrification

Electrification is considered to be a load adder to the forecast. The Company incorporates both residential and commercial/industrial electrification into the ten-year system peak load forecasts. For both residential and commercial/industrial electrification the following adoption rates were used:

- Adoption (% of Total Forecasted Load Incorporated per Year)
    - 2025-2029 – 1%
    - 2030-2034 – 2%

<u>Residential Electrification:</u>

The Company considers two types of residential electrification in its load projections, appliance load and heating/air conditioning load. In order to develop load forecasts for each of these load types the company made the following assumptions:

- Average square footage of a residential dwelling in the service territory of 1,500 sq. ft.
- Heating/AC Sizing[15]
    - 20 btu/sq. ft. for air conditioning
    - 50 btu/ sq. ft. for heating
- Heating/AC Air Source Heat Pump SEER of 18 (13.68 btu/W) (based upon manufacturer data for an "average" efficiency unit)
- Heating/AC Ground Source Heat Pump 40% more efficient than Air Source Heat Pump
- Type
    - 10% Ground Source Heat Pump
    - 90% Air Source Heat Pump
- Current customer AC usage
    - 30% with central AC
    - 40% with window AC
    - 30% with no AC
- All natural gas customers have gas heat, ranges and dryers.
- Typical Electric Dryer Peak Load of 5kW[16]
- Typical Electric Range Peak Load of 6kW[17]
- 80% of all residential customers will convert to electric heat by 2050[18]
- Hourly Utilization Percentages

[15] Based upon International Energy Conservation Climate Zone Map
[16] Based upon typical nameplate data and National Electric Code loads.
[17] Based upon typical nameplate data and National Electric Code loads.
[18] Based upon Commonwealth Clean Energy and Climate Plan for 2050, https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050

Hour of Day	Appliance	Heat/AC	Hour of Day	Appliance	Heat/AC
0:00	5%	50%	12:00	25%	65%
1:00	5%	50%	13:00	25%	65%
2:00	5%	50%	14:00	10%	80%
3:00	5%	50%	15:00	10%	80%
4:00	5%	50%	16:00	25%	80%
5:00	10%	65%	17:00	25%	80%
6:00	15%	65%	18:00	25%	80%
7:00	25%	80%	19:00	25%	80%
8:00	25%	80%	20:00	10%	80%
9:00	10%	65%	21:00	10%	80%
10:00	10%	65%	22:00	10%	65%
11:00	10%	65%	23:00	5%	50%

Table 24 – Hourly Electrification Utilization

The assumptions above along with coincident assumptions, which decrease over time based on the amount of electrification are used to develop hourly residential electrification peak day forecasts. The hourly residential electrification forecasts are then added to the hourly base seasonal peak load forecasts.

Commercial/Industrial Electrification:

The Company utilizes peak gas loads for all commercial/industrial gas customers as the basis for the commercial/industrial electrification load forecasts. In addition, typical hourly electric profiles for the same customer types and the following assumptions are used to develop hourly commercial/industrial electrification load forecasts. These forecasts are then added to the hourly base seasonal peak load forecasts.

- Estimates Peak Hour Gas Usage[19]
    - “Small” Commercial/Industrial – 437 DTH
    - “Large” Commercial/Industrial – 61 DTH
- 293 kW/DTH
- % of Customers to Electrify[20]
    - “Small” Commercial/Industrial – 87%

[19] Based upon “average” Unitil customer

[20] Based upon Commonwealth Clean Energy and Climate Plan for 2050, https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050

- “Large” Commercial/Industrial – 52%

As was the case for DER, ESS and EV Company then developed various ranges of adoption, both above and below the baseline forecasted amount of electrification load. Electrification adoption rates in these scenarios are as high as 15% to 25% above and 10% to 15% below the baseline EV forecasts.

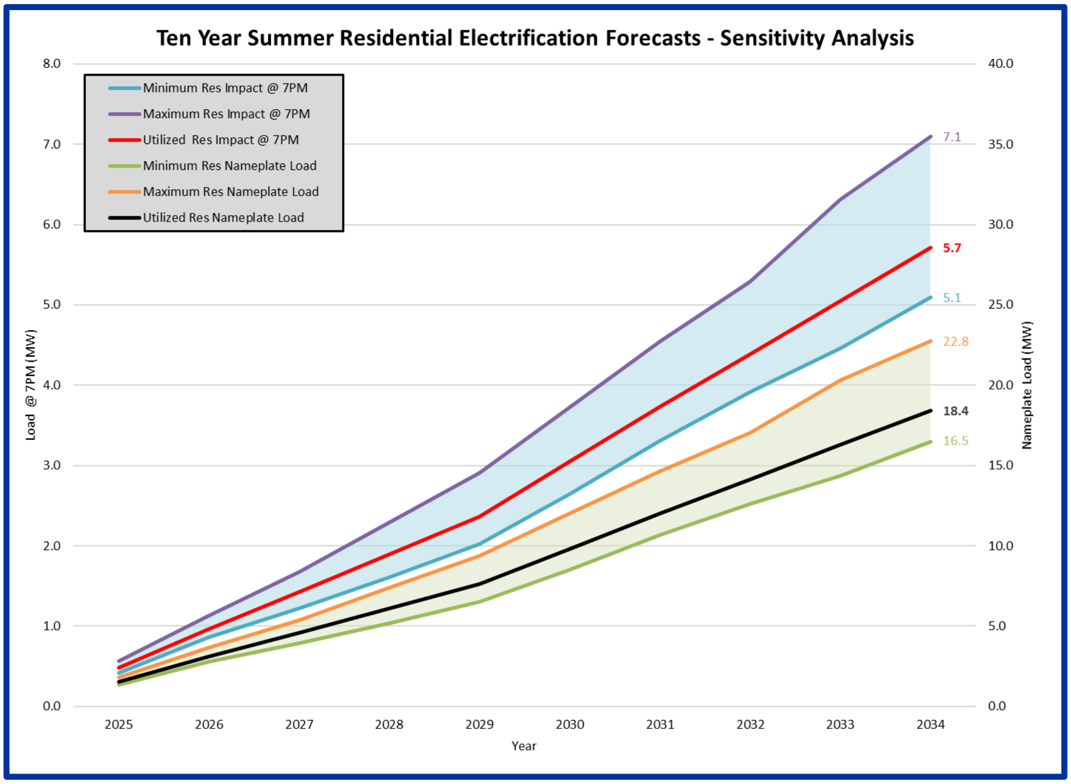


Figure 25 – Ten Year Summer Residential Electrification Forecasts – Sensitivity Analysis

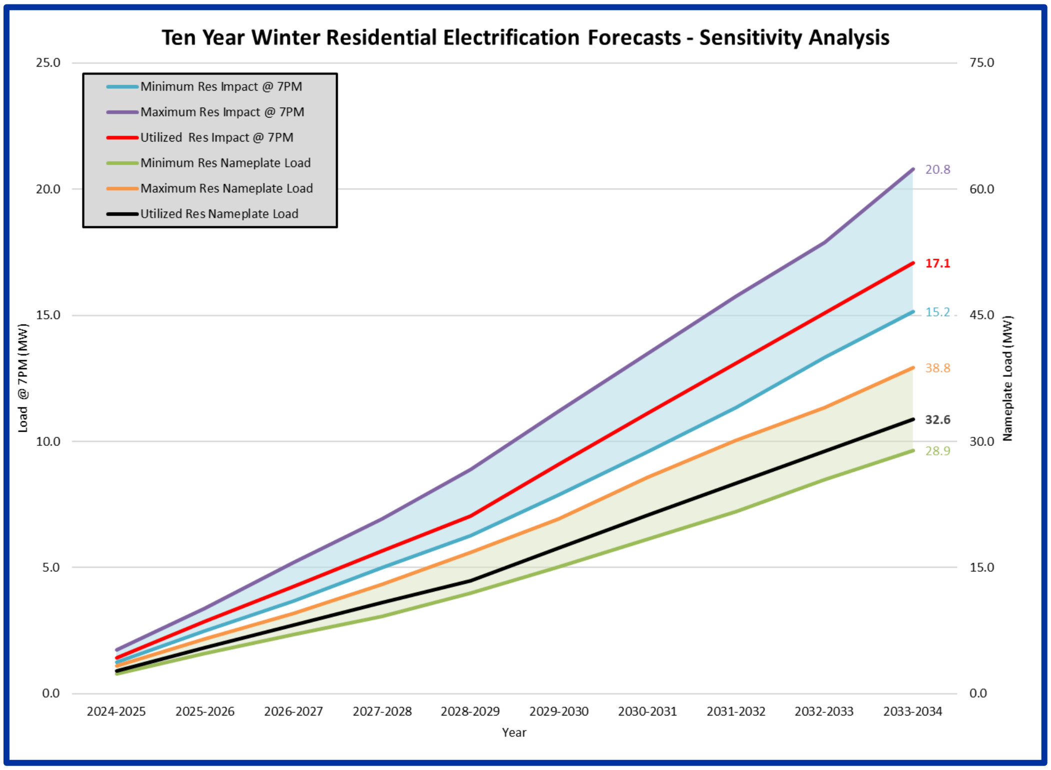


Figure 26 – Ten Year Winter Residential Electrification Forecasts – Sensitivity Analysis

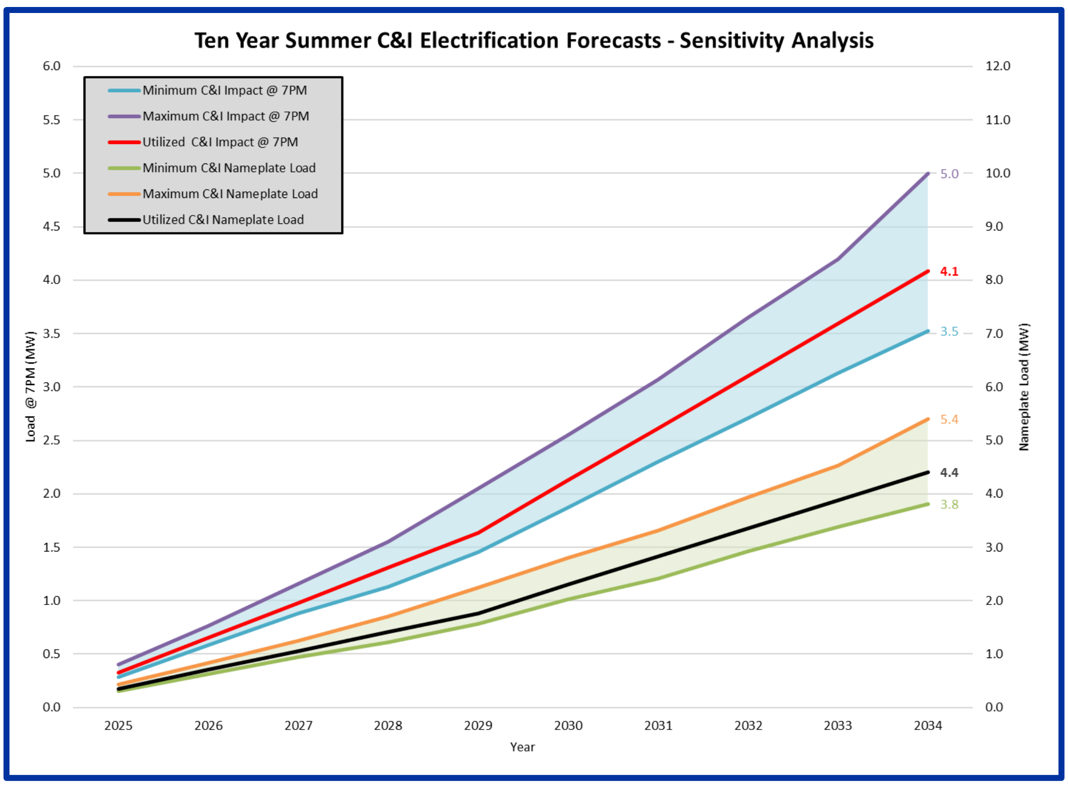


Figure 27 – Ten Year Summer C&I Electrification Forecasts – Sensitivity Analysis

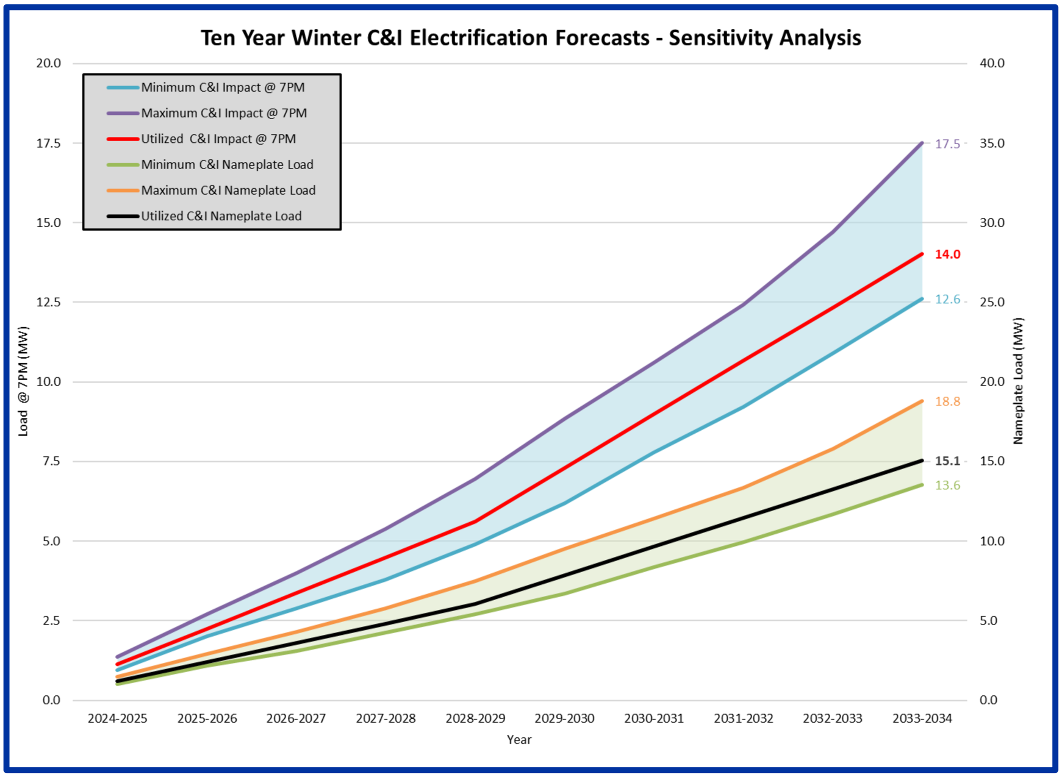


Figure 28 – Ten Year Winter C&I Electrification Forecasts – Sensitivity Analysis

The 10-year load forecast is based upon the most up to date information on building codes and building weatherization technologies. The Company will continue evaluate the most up to date information on changes to building codes and weatherization technologies as part of its annual forecast and determine the impact the changes to building codes and weatherization technologies may have on the load forecasts.

5.1.7 VVO

VVO is considered to be a load reducer in the Company's load forecast. In addition to DER and electrification load forecasts the Company also includes load reduction due to VVO implementation. The Company anticipates a 2% reduction in current loads when VVO is implemented. To incorporate VVO reductions in the ten-year peak load forecasts the Company assumes the following savings.

- Base Load Forecasts – 2% reduction
- Residential Electrification – 1% reduction
- Commercial/Industrial Electrification – 0.75%
- EV – 2%

These savings equate to an overall load reduction when VVO is fully deployed of approximately 1.75%.

Current load curtailment is inherent in the Company's base forecasts as a basis of those forecasts, and relies on historical peak data which weights recent peak years more heavily than other years. It is the Company's intent to include distribution demand response in future load forecasting, however, before this can occur distribution demand response programs need to be created and established. Once established the Company will incorporate the estimated demand response savings associated with these programs into its load forecasting methodologies.

5.1.8 10-Year Peak Load Forecasts

Hourly interval load forecasts for both the winter and summer season for each of the ten years are developed by combining the hourly interval base, DER, ESS, EV and electrification forecasts above. The different adoption ranges for each forecast type are combined to develop a sensitivity review of the various adoption scenarios. Load reduction associated with VVO is included in the Company's peak load forecasts, but was not included in the sensitivity analysis as it is a direct function of the load. The overall system peak load forecasts are the peak hourly load (winter or summer) or each year. Unitil's ten-year system peak load forecasts are included below.

In the case of the electric system, additional PV adoption/installations has a relatively small impact on the "reduction" of overall winter or summer peak loads. The current penetration of PV interconnected to the electric system has shifted the typical summer peak hour (approximately 7PM) and the winter peak hour (approximately 6PM) has remained at times in the evening with minimal PV production.

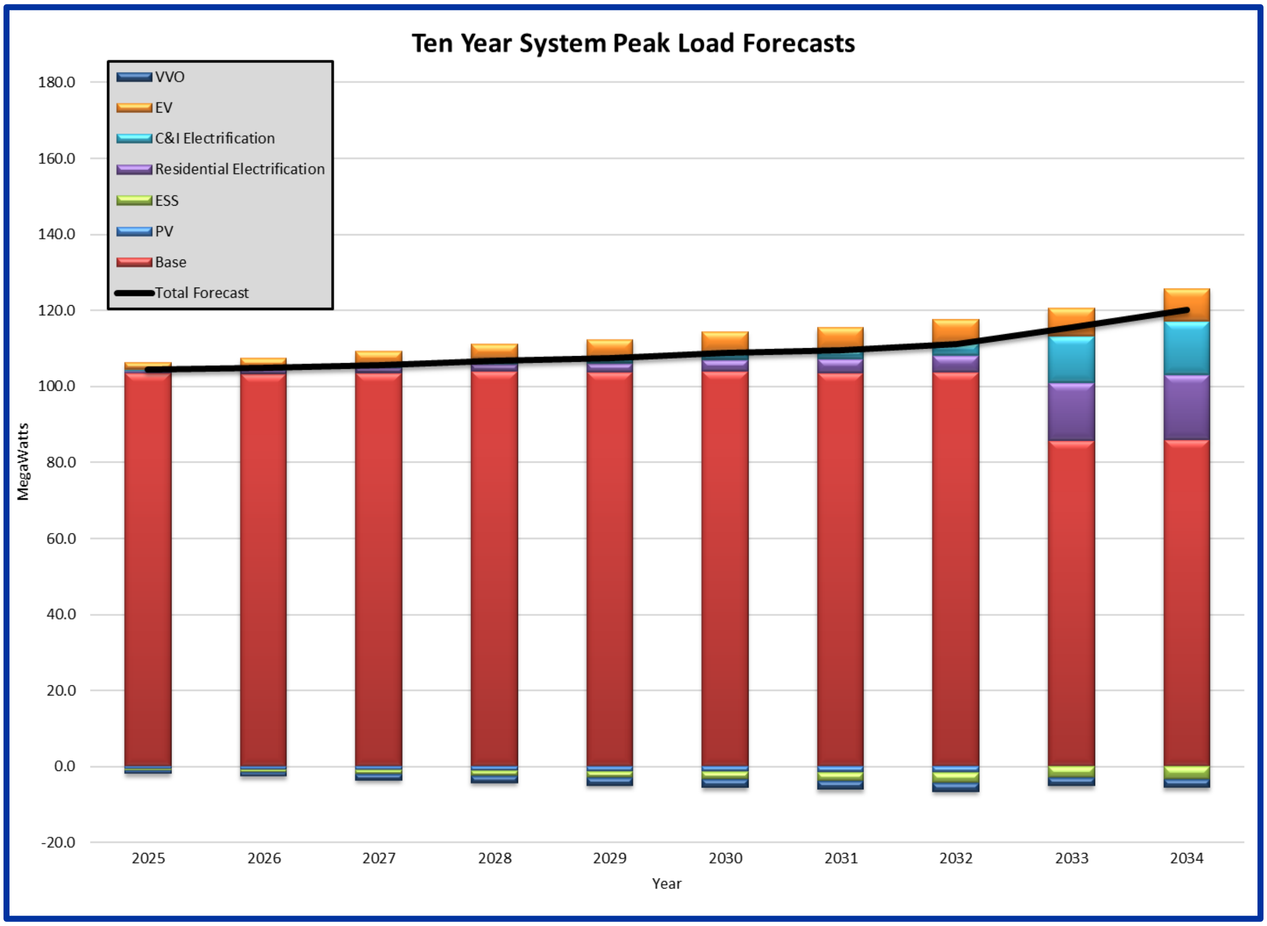


Figure 29 – Ten Year System Peak Load Forecast

Year	Total Peak Forecast (MW)	Contribution to Peak (MW)							Season	Hour
		Base	PV	ESS	Residential Electrification	C&I Electrification	EV	VVO		
2025	104.4	103.6	-0.6	-0.5	0.5	0.3	1.9	-0.8	Summer	7PM
2026	104.8	103.2	-0.8	-0.8	1.0	0.7	2.5	-1.0	Summer	7PM
2027	105.6	103.5	-0.9	-1.1	1.4	1.0	3.3	-1.6	Summer	7PM
2028	106.8	104.0	-1.1	-1.4	1.9	1.3	3.9	-1.8	Summer	7PM
2029	107.4	103.8	-1.2	-1.7	2.4	1.6	4.6	-2.1	Summer	7PM
2030	108.8	103.9	-1.4	-2.0	3.0	2.1	5.3	-2.2	Summer	7PM
2031	109.4	103.4	-1.5	-2.3	3.7	2.6	5.7	-2.2	Summer	7PM
2032	111.1	103.8	-1.7	-2.6	4.4	3.1	6.4	-2.3	Summer	7PM
2033	115.5	85.9	0.0	-3.0	15.1	12.3	7.2	-2.1	Winter	6PM
2034	120.2	86.0	0.0	-3.4	17.1	14.0	8.7	-2.2	Winter	7PM

Table 25 – Ten Year System Peak Load Forecast

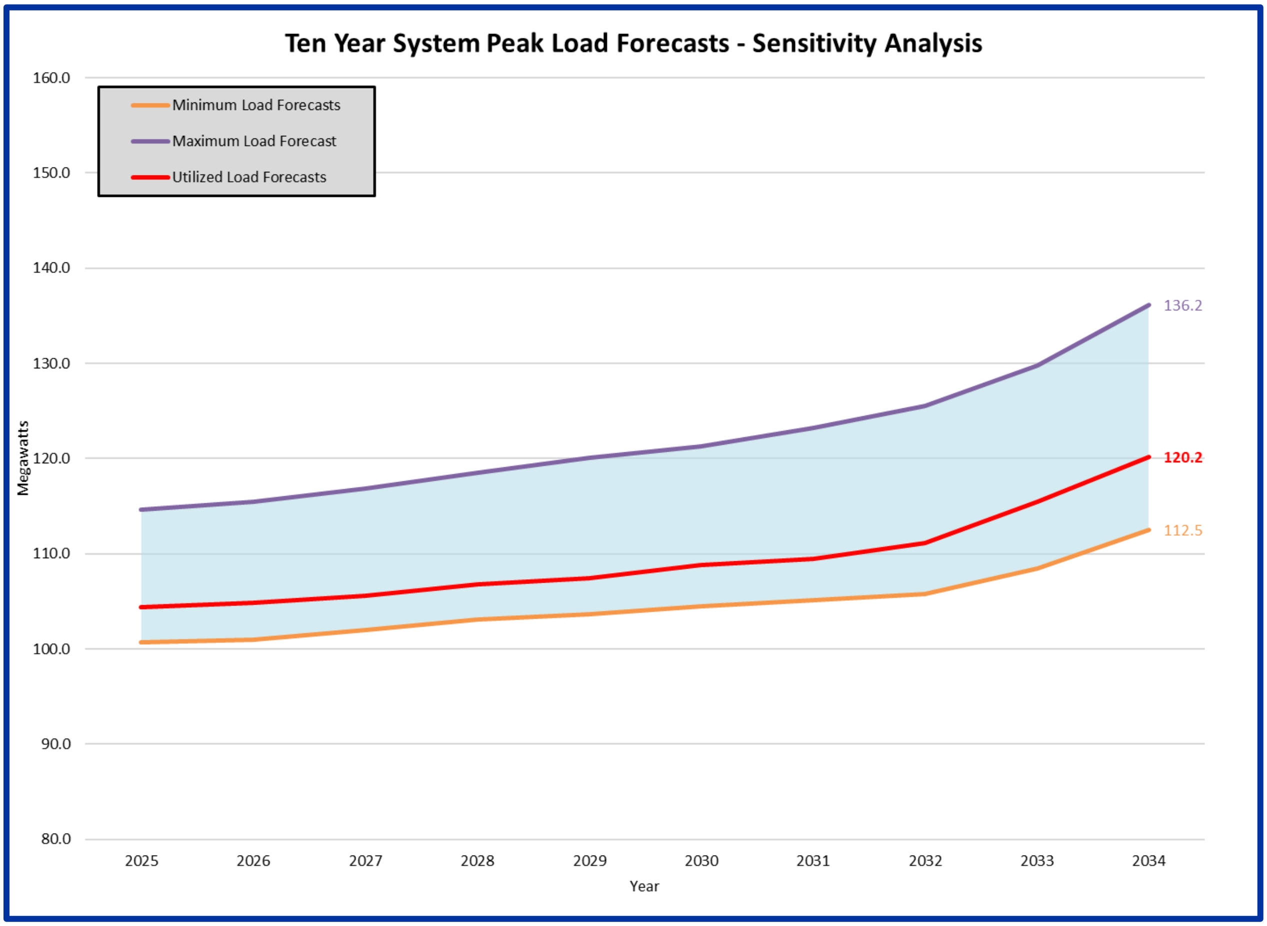


Figure 30 – Ten Load Forecasts – Sensitivity Analysis

The table below provides more detail on the load forecast from a number of units and amount of load perspective. These values provide the basis for the 10-year load forecast.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Additional PV (Nameplate Capacity - kW)	5,976	7,431	8,886	10,341	11,796	13,251	14,706	16,161	17,616	24,771
Electric Vehicles (# Vehicles)	426	607	788	970	1,150	1,325	1,497	1,688	1,967	2,291
% of Total Registered Vehicles	0.8%	1.1%	1.5%	1.8%	2.1%	2.5%	2.8%	3.1%	3.6%	4.3%
Electric Vehicles (# Home L1 Chargers/Plugs)	94	134	174	215	254	293	331	373	435	507
Electric Vehicles (# Home L2 Chargers/Plugs)	285	407	528	650	770	888	1,003	1,131	1,318	1,535
Electric Vehicles (# Public L2 Chargers/Plugs)	29	42	54	67	79	91	103	116	135	157
Electric Vehicles (# Workplace L2 Chargers/Plugs)	48	68	88	108	128	148	167	189	220	256
Electric Vehicles (# DCFC Facilities – 600kW each)	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0	5.5	6.0
Residential Electrification (# Appliances)	128	256	384	513	641	833	1,025	1,217	1,410	1,602
Residential Electrification (BTU of Heating)	19,081	38,163	57,244	76,326	95,407	124,029	152,652	181,274	209,896	238,518
Residential Electrification (BTU of AC)	2,385	4,770	7,156	9,541	11,926	15,504	19,081	22,659	26,237	29,815
Residential Electrification (# Homes Adding Heat Pumps)	211	423	634	845	1,057	1,374	1,691	2,008	2,325	2,642
"Small" C&I Electrification (DTH)	3.8	7.6	11.4	15.2	19.0	24.7	30.4	36.1	41.8	47.5
"Large" C&I Electrification (DTH)	0.3	0.6	1.0	1.3	1.6	2.1	2.5	3.0	3.5	4.0
Energy Storage System (Nameplate Capacity - kW)	1,800	3,000	4,200	5,400	6,600	7,800	9,000	10,500	12,000	13,500
Energy Storage System (Nameplate Capacity - kW)	10,200	17,000	23,800	30,600	37,400	44,200	51,000	59,500	68,000	76,500

Table 26 – Load Forecast Contributions by Type

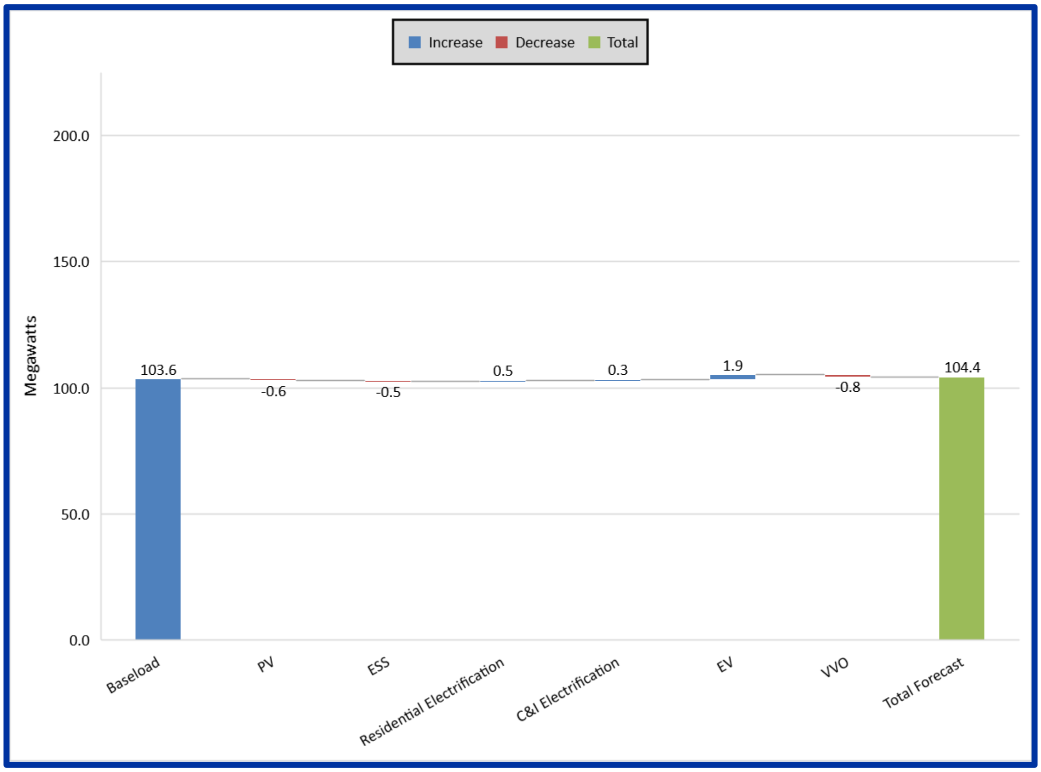


Figure 31 – 2025 Load Forecast Contributions

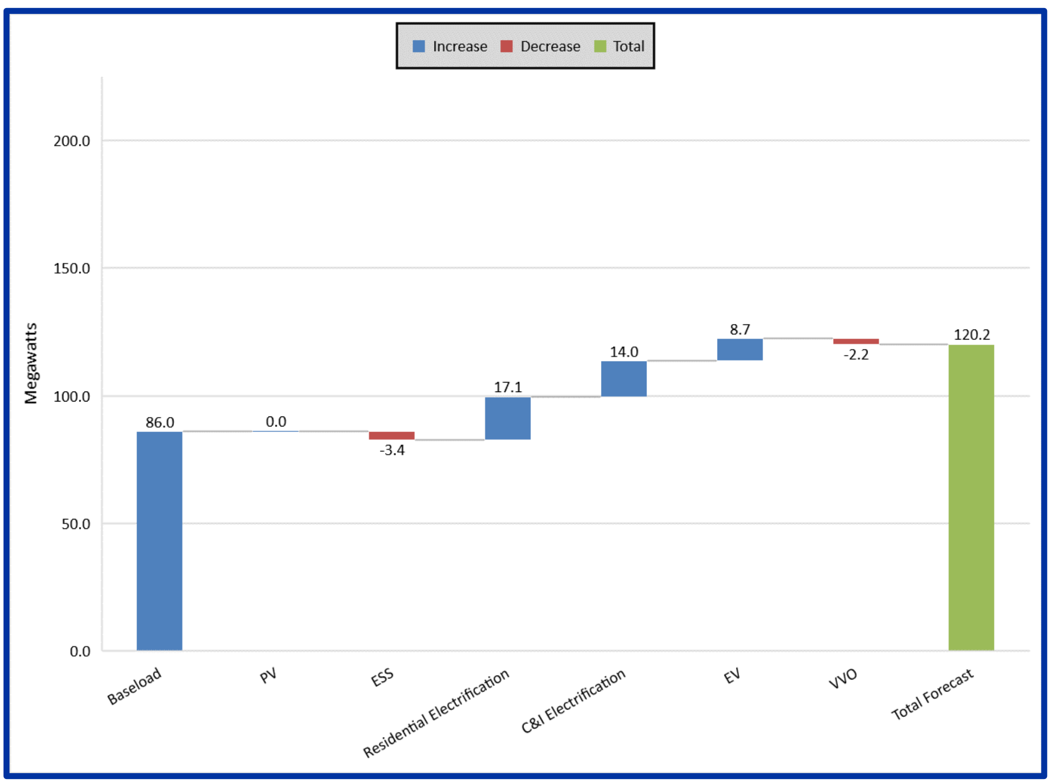


Figure 32 – 2034 Load Forecast Contributions

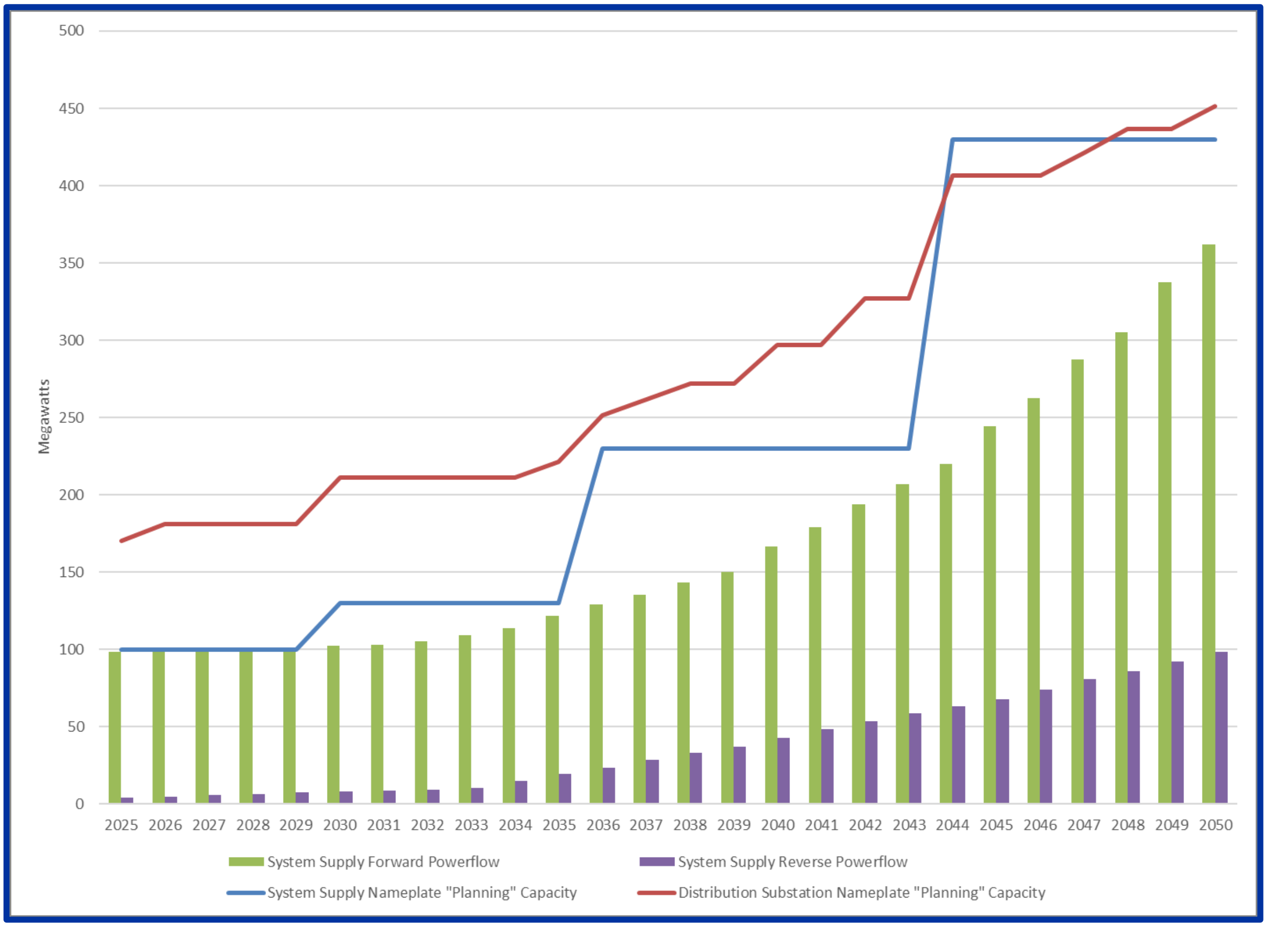


Figure 33 – 25 Year Transformer Capacity Forecasts

It is the Company's intent to continue to monitor and review existing and in-process building codes to determine what changes, if any, are required to load forecasting methodology. In general, building code revision would only apply to new construction and would not require modifications to existing buildings unless modifications drive changes to existing building stock. For new construction any changes to electric load will be reflected through the customer transformer sizing. Additionally, the Company will be aware of changes to loading of existing buildings as it is the customer's obligation to inform the Company of such modifications. The Company's planning and load forecasting team is also responsible for new customer load reviews or load reviews for modified construction, so this allows for these types of load changes to be incorporated into the planning and load forecasting process.

6 5- AND 10-YEAR PLANNING SOLUTIONS: BUILDING FOR THE FUTURE

The Company uses the load forecast to identify the timing system constraints. This section begins with a description of the planning process, existing capital spending plan, previously approved capital spending plans (i.e. grid modernization and electric vehicles) and proposed capital spending.

The annual planning process starts with engineering studies performed by the Company's engineering group. This includes: system studies performed using load flow analysis; circuit studies performed using circuit analysis software and protection studies; and area reliability studies. These studies are updated annually with the latest load forecasts at the circuit level and at the transmission level and are employed to identify both short-term and long-term needs. Engineering planning studies are the first and most important input into the capital planning process.

The load forecasts are used in the analysis to determine when electric system equipment may likely exceed the planning limits. Power flow simulations and circuit analysis are performed for normal and contingency configurations. From these simulations, system deficiencies are identified. System deficiencies are reviewed in additional detail to determine the severity of the concern. System improvement alternatives are developed and tested to assess the impact they had on the identified deficiencies. Cost estimates are developed for each improvement alternative, and a cost benefit comparison is made for the improvement plan options. Final recommendations represent the proposed system improvement plan.

Capital budgets are constructed using a "bottom up" process each year with input from dozens of engineering, operations, and IT employees. Technical and managerial personnel with responsibility for planning, designing, operating, and maintaining the electric delivery system are responsible for identifying needs and developing cost-effective solutions. A multistep process is used to budget hundreds of individual projects, and to then prioritize needs and determine which projects are essential to meet our objective of safe and reliable service for our customers. Projects are also proposed that may not be essential, but which represent an improvement or enhancement to existing systems or capabilities, including projects to improve reliability, replace old or obsolete equipment, and projects with a defined economic payback.

After several rounds of review involving multiple levels of engineering and operations management, a preliminary budget is recommended to senior management for review and approval. Upon approval by senior management, the final budget is presented to the Board of Directors for final approval.

6.1 SUMMARY OF EXISTING INVESTMENT AREAS AND IMPLEMENTATION PLANS

6.1.1 EXISTING CAPTIAL PLAN

The Company's existing or "business as usual" capital budget consists of the following types of projects:

- Annual Blankets - This category includes blanket authorizations for categories of projects where each individual project is small in value (under $30,000) and cannot be individually anticipated at budget time. These projects are budgeted and authorized under a single blanket authorization representing the anticipated aggregate level of spending. The categories are generally self-explanatory. For example, distribution improvements include: minor upgrades and replacements and repairs to the distribution system; new customer additions consist of new customer requests for service including new services and small line extensions; outdoor lighting includes repairs and replacements of existing street lights and customer lighting fixtures; emergency and storm restoration includes capital repairs and replacements required to restore service to customers following storms or outages; billable work includes customer projects, pole accidents, cable TV projects and other projects where all or a portion of the work is billable; and, lastly, transformer and meters are for the purchase of transformers and meters.
- Distribution - These projects are individually authorized projects involving capital additions where the value of the project exceeds the maximum threshold allowed under blanket authorizations. The projects are generally self-explanatory. For example, overhead and underground line extensions are new extensions of primary facilities required to provide service to customers; street light projects are new projects to add street lighting; telephone company requests include pole replacements and relocations required under our agreements with Verizon or other pole attachees; highway projects are typically line relocations driven by state or municipal roadway projects; distribution and sub-transmission poles replacements include costs associated with replacing poles that failed inspection during the Company's 10-year pole inspection program; and, specific projects are all other projects in excess of $30,000 that are identified by engineering or others that are needed to meet service obligations.
- Substations - These are individually-authorized projects involving projects and capital additions to distribution substations. Each project is individually budgeted and

authorized. The projects are typically identified by engineering, though the projects may also be identified as the result of inspection and maintenance activities.

- Grid Modernization - These are individually-authorized projects that have received pre-authorization under the Company's filed Grid Modernization Plan. See the description below. These projects have been previously authorized as part of D.P.U. 15-121 and D.P.U. 21-82.
- Others - Communications include additions and replacements of communication-related equipment such as SCADA, radio systems for field communications, and communication equipment for the Company's AMI system; tools, shop, and garage includes most tools and test equipment used by electrical workers in the performance of their job; laboratory includes test equipment used to test meters and other devices.

6.1.2 GRID MODERNIZATION

In D.P.U. 21-82, the Department approved the Company's 2022-2025 Grid Modernization Plan. The Plan proposed a continuation of previously authorized projects in addition to new projects. The Department subsequently authorized investments for: 1) SCADA; 2) AMI/OMS Integration; 3) VVO; 4) Field Area Network; 5) ADMS/DERMS; 6) Mobile Damage Assessment Platform; 7) DER Mitigations; 8) AMI Meter Replacements; 9) Customer Engagement and Experience; and 10) Data Sharing Platform.

Project / Project Category	2025	2026	2027	2028	2029	2025-2029 Total
SCADA	$ 100	$ 0	$ 0	$ 0	$ 0	**$ 100**
AMI/OMS Integration	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
VVO	$2,400	$ 0	$ 0	$ 0	$ 0	**$2,400**
Field Area Network	$ 179	$ 0	$ 0	$ 0	$ 0	**$ 179**
ADMS/DERMS	$ 125	$ 0	$ 0	$ 0	$ 0	**$ 125**
Mobile Damage Assessment	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
DER Mitigation	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
AMI Meter Replacements	$ 339	$ 0	$ 0	$ 0	$ 0	**$ 339**
Customer Engagement	$ 465	$ 0	$ 0	$ 0	$ 0	**$ 465**
Data Sharing	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
Total Costs (000s)	**$ 3,608**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 3,608**

Table 27 – Approved Grid Modernization Capital Spend ($000's)

Project / Project Category	2025	2026	2027	2028	2029	2025-2029 Total
SCADA	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
AMI/OMS Integration	$ 11	$ 0	$ 0	$ 0	$ 0	**$ 11**
VVO	$ 5	$ 0	$ 0	$ 0	$ 0	**$ 5**
Field Area Network	$ 10	$ 0	$ 0	$ 0	$ 0	**$ 10**
ADMS/DERMS	$ 178	$ 0	$ 0	$ 0	$ 0	**$ 178**
Mobile Damage Assessment	$ 50	$ 0	$ 0	$ 0	$ 0	**$ 50**
DER Mitigation	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
AMI Replacement	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
Customer Engagement	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
Data Sharing	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
Third Party Verification	$ 75	$ 0	$ 0	$ 0	$ 0	**$ 75**
Total Costs (000s)	**$ 329**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 329**

Table 28 – Approved Grid Modernization O&M Spend ($000's)

6.1.3 ENERGY EFFICIENCY

The Energy Efficiency programs the Company offers are developed as part of a comprehensive and collaborative approach to optimizing energy use by electricity and natural gas customers. These efforts aim to transform the marketplace for energy-using services and equipment in the built environment by working with distributors and retailers, building and installation contractors, and end use customers in the commercial, industrial, and residential sectors.

The Company works collaboratively with the state regulatory agencies and interested stakeholders to develop energy efficiency programs designed to meet state goals. The Company implements cost-effective EE in pursuit of annual energy saving goals established through a robust stakeholder process. The Company's EE programs are informed by nearly two decades of experience working with stakeholders, consultants, our colleagues at the other gas and electric utilities, as well as our customers.

The Company's existing portfolio of EE programs focuses on customers in three categories: non-low-income residential customers, low-income residential customers, and commercial and industrial customers. The primary electricity-saving residential offering provides discounted retail pricing to residential customers who purchase high efficiency lighting and electric appliances. The Company collaborates with retailers, distributors and the other electric utilities to ensure that high efficiency products are marketed to customers, and that point-of-sale discounts are provided to customers on high-efficiency promoted products.

By moving consumers and contractors away from less efficient products and appliances, our incentives continue to transform the market for lighting and equipment and train customers to consider not just up-front cost but lifecycle costs. For more substantial and expensive projects involving heat pumps or whole-home weatherization, the Company offers on-bill and third-party financing options that allow customers to spread their share of the investment over a longer period of time and experience cash-flow positive savings. For income eligible customers, the Company pays 100 percent of the cost of energy improvements, eliminating one of the major barriers to participation for these customers.

In the C&I sector, the Company works closely with retailers and distributors to ensure that high efficiency lighting, motors and drives, Heating, Ventilation and Air Conditioning ("HVAC"), controls and other equipment are an accessible and attractive choice for contractors, builders and end use customers. By providing both technical assistance and cash incentives, our efficiency programs reduce the barrier that a higher up-front cost presents to C&I customers, including municipalities and nonprofit organizations. As in the residential sector, on-bill financing programs allow qualifying commercial and industrial customers to offset some or all of the up-front cost of new or retrofitted equipment that is not covered by the program's cash incentive.

For both residential and commercial and industrial customers, the Company provides technical assistance, training and cash incentives to ensure that new buildings are built and equipped to high EE standards. This assistance is facilitated not only by the Company's key account managers, but supplemented by engineering and design-build firms that are familiar with both good building design and with our incentive programs.

In the residential programs, a fuel-blind approach to energy use results in significant heating fuel savings in programs focused on new construction and weatherization of existing homes. Just under half of the resulting energy savings comes from a reduction in electricity use from high efficiency HVAC, appliances and lighting.

For the commercial and industrial sector, the majority of savings come from custom projects among manufacturers, retail establishments, municipalities, and schools. While high efficiency lighting and controls continue to be the most important single contributor to overall EE savings, the Company is dedicated to reducing both energy use and demand by incenting high efficiency HVAC measures, motors and drives, appliances, plug loads, and process equipment. Technical assistance, professional referrals and financial assistance help customers to overcome non-cost barriers to the adoption of energy efficient equipment and operations. Based upon the 2022-2024 EE plan, the expected passive and active energy savings is approximately 0.5 MW.

The Company is not intending to forecast EE spending as the EE plan and funding levels are adjudicated in a separate process. The table below assumes the 2024 Plan spending continues at the same funding level throughout the 2025 - 2029 timeframe.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 0	$ 0	$ 0	$ 0	$ 0	**$0**
O&M Costs (000s)	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	**$40,000**
Total Costs (000s)	**$ 8,000**	**$ 8,000**	**$ 8,000**	**$ 8,000**	**$ 8,000**	**$ 40,000**

Table 29 – EE Plan Spending

6.1.4 EV CHARGING AND MAKE READY PROGRAMS

The transportation sector continues to be the largest contributor of GHG emissions in the Commonwealth of Massachusetts.[21] In docket D.P.U. 21-92, the Department approved the Company's five-year[22] EV program with a $998,000 budget consisting of: (1) public segment ($528,000); (2) residential segment ($300,000); and (3) marketing and outreach ($160,000).[23] The Department found it appropriate to limit the availability of residential program Electric Vehicle Supply Equipment ("EVSE") rebates for one to four-unit properties to low-income customers, who face the greatest financial barriers to EV adoption. The Department approved the Company's proposal to provide 100 percent EVSE rebates to residential customers in one to four-unit dwellings who qualify for its low-income residential discount rate and are enrolled in its EV Time of Use ("TOU") rate, up to the Company's proposed project cap.

This is the first approved EV program for the Company and the learnings from this program will be used to inform changes to future programs. The program is designed to support the growth of electric vehicles in Massachusetts by providing incentives to public and residential charging.

The Company's AMI system allows the Company to be uniquely positioned to provide EV TOU rates. TOU rates will encourage energy conservation and the optimal and efficient use of grid facilities, and will mitigate increases in peak demand. The Company's rate offering includes an EV TOU rate and demand charge alternative pram for general deliver service applications. Given the dynamic nature of the transportation market and the wide variety of customer travel needs,

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[21] https://ma-eeac.org/wp-content/uploads/Exhibit-1-Three-Year-Plan-2022-2024-11-1-21-w-App-1.pdf at page 15
[22] "Five-year" covers 2023-2027
[23] Docket D.P.U. 21-92 Order at 169

it is unlikely that any one option will be suitable for all customers. Innovative rate designs will afford customers the opportunity to adopt new technologies, manage energy consumption and enhance efficient utilization and consumption of electricity to save money.

The Company's EV program is designed to alleviate barriers to EV adoption. The program offers $1,000 rebates to residential customers enrolled on the EV TOU rate and living in 1-4 unit dwelling for the installation and procurement of Level 2 EV chargers.

The program is designed to provide an increased incentive to income-eligible customers. Income-eligible customers receive rebates covering 100% of the installation and procurement of smart, Level 2 EV chargers up to $1,700.

The program also offers a make-ready EV infrastructure program essential to the development of public EV charging stations throughout Massachusetts. The make-ready program targets investment of approximately $528,000 over five years to deploy EV charging at approximately 5 Level 2 and 1 DCFC public sites (total of 6 sites) in the Company's service area. The Company further proposes to install required upgrades on the distribution system and to contract with third-party electrical contractors to install behind-the-meter "customer-side" infrastructure. The Company will target make-ready site hosts with publicly-available, long-dwell time parking including Environmental Justice and low- and moderate-income communities.

The proposed make-ready program represents a significant increase in Company-supported, customer-sided and behind-the-meter infrastructure. A make-ready program is necessary to expand the Commonwealth's network of charging stations and will reduce barriers to investments in EV charging infrastructure.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 106	$ 106	$ 106	$ 0	$ 0	**$318**
O&M Costs (000s)	$ 92	$ 92	$ 92	$ 0	$ 0	**$270**
Total Costs (000s)	**$ 196**	**$ 196**	**$ 196**	**$ 0**	**$ 0**	**$ 588**

Table 30 – Approved EV Plan Spending[24]

[24] Docket D.P.U. 21-92 Order at 169. DPU approved five-year EV program (2023-2027) with a $998,000 budget consisting of: (1) public segment ($528,000); (2) residential segment ($300,000); and (3) marketing and outreach ($160,000). Plan assumes flat spending over 5 year period.

To keep pace with the state's goals for EV adoption, the Company is proposing to double the approved per year spending during the last two years of this plan.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 0	$ 0	$ 0	$ 212	$ 212	**$0**
O&M Costs (000s)	$ 0	$ 0	$ 0	$ 184	$ 184	**$0**
Total Costs (000s)	**$ 0**	**$ 0**	**$ 0**	**$ 396**	**$ 396**	**$ 792**

Table 31 – Proposed EV Plan Spending

6.1.5 HEATING INCENTIVE PROGRAMS

As indicated in the 2022-2024 Mass Save energy Efficiency Plan[25] after the transportation sector, the largest source of GHG emission is the building sector. The EE Plan relies on electrification of the heating sector to drive reductions in the GHG emissions. The current plan focuses on transitioning customers who are more likely to experience reduced heating costs when transitioning from oil, propane, or electric resistance heating to heat pump technology. The Company believes heating incentives will continue to play an increasingly more important role in subsequent plans.

The spending associated with heating incentives is included in the EE spending plan above.

6.1.6 DEMAND RESPONSE PROGRAMS

The Company offers an active DR program through Mass Save. The program incentivizes customers to reduce their load during identified times of system peak demands. Lower peak demands help to defer system investment while reducing charges from transmission and generation. This program can influence both the long-term forecasting methodology ISO-NE uses to establish the Installed Capacity Requirement, as well as the price of capacity in the Forward Capacity Market.[26] Active Demand Response activities can be aggregated and bid into the Forward Capacity market, resulting in financial incentives to those who participate

Through the Mass Save program, the program administrators will scale up active demand response offerings for C&I customers as well as residential customers. The C&I customer

[25] https://ma-eeac.org/wp-content/uploads/Exhibit-1-Three-Year-Plan-2022-2024-11-1-21-w-App-1.pdf at page 11
[26] https://ma-eeac.org/wp-content/uploads/Exhibit-1-Three-Year-Plan-2022-2024-11-1-21-w-App-1.pdf at page 32

program is designed to target the peak hour of the system. Transmission costs are allocated on the peak hour load, therefore a reduction in load at the peak hour can have a significant impact on the cost allocation. Reduction events are generally noticed a day in advance and then dispatched at the specific time of day when the reduction is needed.

Active demand response can be effective at reducing system peak load. However, at a local level, the program administrators must be confident in the loads being reduced to be included and considered as a grid asset. The Mass Save program has an "opt-out" capability, so customers can choose not to participate on any given day. This does not lend itself to a reliable asset the Company can rely upon to ensure system performance.

The spending associated with demand response incentives is included in the EE spending plan above.

6.1.7 CIP Projects

The Company has not proposed any CIP projects for adjudication outside of the ESMP process, nor has the Company proposed any CIP projects as part of this ESMP. The Company is willing to work with the EDCs, stakeholders and Department on a collaborative approach to addressing the stakeholders concern that the existing CIP adjudication process can be lengthy and time consuming process.

6.2 DESIGN CRITERIA CHANGES

Distribution planning and design standards are critical components to safe and reliable design and operation of the electric system. These standards are based upon industry best practices as well as historical weather conditions (i.e. ice, wind, and temperature). Climate change may have an impact on planning and design standards as industry best practices change to account for changes in future weather conditions.

The Company is considering the following impacts to its planning and design criteria:

- Ice and Wind Loading – The Company currently uses the National Electric Safety Code for ice and wind loading criteria when designing our electric system. The Company will utilize future climate planning efforts to inform future changes to the ice and wind loading criteria used in future designs.
- Standard Equipment Capacity Ratings – The increase in electrification will increase loads on the electric system. The Company will utilize future climate planning efforts to inform

future changes to equipment sizes to determine if increasing standard equipment capacity ratings are appropriate.

- Equipment Ratings – Existing load curves allow for times of light load and cooling. As the load curve flattens, the opportunity for cooling at lighter loads diminishes. To the extent necessary, the Company will evaluate the impact that rising temperatures and changing load cycle curves have on equipment ratings.
- Outage Criteria – With the increase in electrification, the tolerance for outages may be impacted. To the extent necessary, the Company will evaluate changes to its outage exposure design criteria (i.e. MW/Hour or CMI/Hour. In addition, climate change may create more frequent and more severe storms. The Company will utilize future climate planning efforts to inform future changes reliability planning criteria relating to climate change.

6.3 TECHNOLOGY PLATFORMS UNITIL IS IMPLEMENTING

6.3.1 Description of implementation justification and expected benefits

Automation

The objective of this project is to implement key SCADA functionality at all of the Company's substations, and at other locations needed to support the ADMS/OMS/VVO applications and other modernization projects. 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 SCADA project is an enabling technology for other projects in the GMP including VVO and ADMS. In conjunction with other components of the Plan, it will support the GMP objectives of reducing the effects of outages and optimizing demand.

In addition to facilitating the ADMS/OMS/VVO and other modernization projects, SCADA monitoring and control at the distribution level is foundational to reducing outage response and restoration times through improved outage awareness, fault location, isolation and system reconfiguration capabilities, both manually or through automation. After implementation, it is estimated that outages originating at SCADA-controlled devices may be reduced by 5 minutes of response time at the front-end and 5 minutes of re-energization time at the back-end of an outage for a total savings of 10 minutes.

The following functionality is intended for the devices where these SCADA additions or modifications are planned:

- Real-time telemetry and historical interval data collection for each included power transformer and circuit position, including the following measurements:
  - Voltage
  - Current
  - Active and Reactive Power
  - Active and Reactive Energy (where required)
- Remote monitoring of live/dead states of included buses, lines and circuits
- Remote monitoring and control of included breakers, reclosers, switches, etc.
- Remote monitoring and control of included transformer LTCs and voltage regulating transformers
- Remote monitoring and control of included capacitor banks

Integration with the ADMS, and the ability to participate in automation schemes suitable to their functions

AMI/OMS Integration

This is a software project to enhance the current AMI to OMS interface. 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.

By proactively detecting, and confirming with a high degree of confidence, valid outages, we expect to save time and money by reducing potentially unnecessary truck rolls and expedite crew deployment. This data may also provide additional near-term related benefits such as reduction in SAIDI times as well as long term applicability towards building more proactive and predictive outage intelligence and analytics. 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 estimated that the AMI system on average will be five (5) minutes faster than customer calls for at least 10% of the outages.

Volt-Var Optimization

The scope of this 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 LTCs. In addition, voltage and energy monitors will also be installed at strategic locations on the circuits. The operation of these control devices will be coordinated and optimized by a central system (potentially ADMS or another software-based system).

The VVO system operates by constantly optimizing 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. This will directly benefit customers by reducing their electricity consumption and thereby reducing their bills. The Company's overall plan is to install VVO on 100% of the Company's circuits. Therefore, all customers will have the opportunity to achieve the benefits of VVO.

Field Area Network

A field area network ("FAN") is a foundational technology that provides the Company with the communications backbone required to install many of the grid modernization initiatives being considered. The installation of a FAN without any of the other functionality does not result in any monetizable benefits. However, the VVO, ADMS, DERMS and SCADA systems cannot provide the benefits identified without a FAN. Each grid modernization type of device the Company installs in the field will be equipped with a modem and connected to the Company's FAN.

ADMS/DERMS

The Company is deploying an ADMS system that supports VVO and unbalanced load flow analysis. In the future ADMS will also support distribution system automation, including automated distribution switching and 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, and OMS will be enhanced to provide the necessary technical information for ADMS to perform the functions described above.

An ADMS system provides 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 integration of outside data sources such as real-time weather and VVO. The ADMS provides the visibility and control required to operate the advanced grid in a safe and reliable manner. The ADMS also provides valuable information during outage events, and will enhance situational awareness resulting in shorter outage durations.

The Company ADMS system is currently being 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
- VVO
- Crew assignments
- Engineering based load flow and circuit analysis tools
- Hardware, software, and training
- Hot standby fault recovery

The Company's ADMS system closely integrates with other enterprise systems in an effort to realize its full potential such as the FAN to provide communication to field devices, the installation of field devices that have the ability to be controlled, and a DERMS which provides the monitoring and control of DERs connected to the system.

ADMS is an enabling technology. The ADMS enables effective VVO, reducing customer energy consumption by 2% and commensurate peak demand reductions. Benefits are already accruing directly to consumers as reductions in electricity bills, and through utilities as reductions in demand charges. The ADMS also enables better voltage control for integration of DER and improved reliability through FLISR. The ADMS serves as a platform for more advanced modules such as DERMS. DERMS provides visibility and control to enable an increased quantity of distributed resources. Quantifiable benefits are shown under the other projects.

An ADMS system provides 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 and network configuration. Additionally, the Company's ADMS utilizes "real-time" unbalanced load flow calculation results to automatically control distribution equipment for VVO.

The plan for ADMS includes the implementation of a DERMS. This is an add-on to the ADMS which provides the ability to manage and control multiple DER facilities and other infrastructure (electric vehicle charging stations, demand response, etc.) including both Company-owned and customer-owned facilities. DERMS provides the information and control necessary to effectively manage the technical challenges posed by a more complex grid. The DERMS system provides the ability to manage the impact of DER and operate the system more efficiently.

Mobile Damage Assessment Platform

This project comprises the implementation of a Mobile Damage Assessment Platform to enable 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 allows for faster and more accurate situational awareness during large-scale weather events.

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. This translates to an estimated savings of approximately 700,000 customer minutes and over $1,000,000 in customer savings based upon the Berkley ICE Calculator.

DER Mitigations

As the proliferation of DER on electric distribution systems increases to levels approaching that of the local distribution loads, challenges caused by reverse power flow and sustained energization become more prevalent. These challenges include adverse impacts on voltage regulation, short-circuit protection and overvoltage protection.

The project objectives in 2022-2025 are to implement overvoltage protection improvements on the 69 kV side of several distribution substations to mitigate the risk of ground-fault overvoltage 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.

At present, mitigations to accommodate the interconnection of DER are identified during impact studies of individual DER projects, and the associated costs are borne by the specific DER project owner(s) causing the need for those mitigations rather than electric customers in general. That has traditionally worked for typical mitigations to accommodate medium to large DER interconnections, since DER projects of those scale have been able to bear those costs that are directly associated with them. However, the reverse power flow and sustained energization concerns that this project is directed towards are the result of aggregate DER spread across multiple distribution circuits, especially high quantities of residential-scale DER, and “next in queue” residential-scale DER projects are not usually able support the extensive costs for mitigations at substation and sub-transmission levels. This project will remove barriers on substations that have reach or are close to reach saturation for DER interconnections.

AMI Replacements

The Company first installed AMI on its system over fifteen years ago. The Company’s original AMI installation was state of the art when it was installed, but has been outpaced by new technology that can provide more functionality. As such, the Company’s 2022-2025 Grid Modernization Plan included an AMI meter replacement plan to transition from its existing TS2 meters to an advanced interval metering functionality that will enable the Company to implement enhanced rate plans, which will provide our customers with the ability to achieve the full benefit of their technology investments or changes in customer user patterns. Benefits to participating customers include lower energy bills.

Due to the discontinuation of the meter technology initially included in Unitil’s AMI plan, the Company issued a competitive request for proposals to meter vendors and meter exchange vendors in December 2022. Following a detailed review process, the Company has selected Landis & Gyr as the meter vendor using an RF communications network that will be installed and maintained by the Company. Key incremental functionality will include, but not be limited to:

- Interval Metering: Interval metering benefits the customer, as well as the electric system as a whole. The Company intends to implement AMI replacements that will enable the provision of real time or near real time granular interval metering to each and every customer. Interval metering provides the data necessary for demand management programs, TOU / TVR rates, and other customized programs focused on controlling or reducing energy consumption. When combined with TVR rate mechanisms, interval metering will not only provide customers with a financial incentive to control their own energy use, but will also enable innovative rate designs to encourage and reward customers for reduced energy consumption during peak load times on the system.

- Advanced Planning and Forecasting: The growing penetration of variable loads and intermittent renewable resources creates a challenge for the electric system if the grid is not prepared to accept these resources. Advanced system planning forms the foundation for such an enabling platform, which will be able and ready to accept DERs and other electrification technologies. Advanced system planning begins with an accurate system model. The Company's intends for its AMI meter replacements to provide loading and voltage information on a real time or near real time basis to facilitate advanced planning and forecasting.

- Data Sharing: Data sharing is a foundational tool that will allow customers and third parties the ability to use data to inform behaviors, products, and programs leading to a reduction in energy consumption. Accurate and timely data will empower customers to make educated decisions that will have a positive effect on the electric distribution system and customer bills. Data sharing may also be a solution to overcoming barriers that may exist for customer adoption of technologies that will benefit the electric system.

- System Monitoring: The Company will use the data provided by the AMI system for real-time monitoring and control of the distribution system. The information from the AMI system will be used by the Company to optimize the electric system through active control of voltage and loading, reducing line losses and allowing for further integration and reliance on distributed energy resources. Constant and pervasive system monitoring and data gathering facilitated by the AMI system is required to manage the high penetration of renewable resources and other DERs connected throughout the system.

- Outage Reporting: Unitil's AMI system will provide information on outages for every meter on the system. Improving the speed of outage information from the field and integration with the OMS outage prediction engine will improve the outage prediction process, reducing false positives and improving the ability to identify the location of nested outages. The data from the AMI system will reduce the number of truck rolls, improve restoration time, and provide dispatch and operations staff the information required to efficiently and effectively manage an outage event.

- Innovative Rate Designs: The overarching objective of rate redesign is the development of pricing for grid services that adhere to the principles of fairness, transparency and economic efficiency. Only through transparent and economically efficient pricing structures will a viable and sustainable long-term model be developed that provides sufficient revenue to support the significant investments needed to modernize the grid, while encouraging appropriate behaviors and assuring fairness and equity among customers. The granular and timely interval metering data will enable innovative rate designs to evolve and enable customers to more effectively manage their energy needs.

The AMI Replacement project schedule is shown below:

Project Task	Schedule
AMI Headend System	Q1-Q3 2024
Network Installation and Commissioning	Q1-Q3 2024
Meter Replacements	Q2 2024 – Q2 2025

Table 32 – AMI Project Schedule

Over time, the impact of this AMI technology is expected to reduce overall market rates for all customers. Additional benefits include lower peak and critical peak energy usage, which can defer investments in equipment; timely and accurate data to support various system, customer, and market facing technologies; and grid facing functions such as distribution management, system planning, and system optimization. Installation of AMI enables improvements in outage monitoring and circuit monitoring due to the increased speed of response from the meters to the head end system.

The Company filed a concept paper through Federal Funding Opportunity Announcement DE-FOA-0002740 titled “BIL – Grid Resilience and Innovation Partnerships” (“GRIP”) for it AMI Replacement project. The Company was encouraged to file a full grant application following review of the concept paper. The Company filed a full grant application in March 2023. In October 2023, the Company was informed that our grant application was not selected for award. Incorporating feedback received from the Department of Energy, the Company again submitted a concept paper in connection with this project in January 2024 and will determine if it will re-apply for GRIP funding.

Customer Engagement and Experience

This project strengthens current service offerings, make enhancements to our customer web portal (or Customer Experience Management Solution), and adds self-service options that enable customers to better manage their energy usage and accounts. These enhancements include a mobile application, 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.

This project designs, develops, tests and implements a robust, personalized self-service solutions providing our customers with a responsive web experience, mobile application, and tailored, timely and proactive notifications for customers over an extended period estimated to commence in 2024. The project is a foundational element to providing customers with energy information, products and services that align with the Company's mission and strategic customer vision roadmap.

This is a foundational project that enables larger product offerings such as TOU rates and as such quantifiable benefits are difficult to calculate for this stand-alone project. The qualitative benefits include: 1) robust content management tools for web-based forms and customized tools; 2) a configurable enterprise notification platform enables real-time service alerts for outage events, TOU rate conditions, and service appointments (to name a few); 3) a mobile application to improve accessibility and ease of use; and 4) provides a foundational platform that enables strategic enhancements such as predicative analytics and artificial intelligence automation.

Easy to understand web-based tools provide customers with the opportunity to control their energy usage. Proactive alerts and preference-driven notifications provide customers with advance notification of changing circumstances. This project provides flexibility through personalized products and service offerings, individualized customer communications, customized energy related advice, and personalized billing and payment options that cover the wide range of users. Enhanced customer communications, alerts and consulting advice educates the customer to make decisions that can reduce cost and increase the overall affordability of their service. Personalized rate plans and access to a transactional energy marketplace provide options to the customer to improve their overall value proposition. Active management of peak demand usage reduces transmission and generation costs, defers costly system improvements and allows the system to operate in a more efficient manner. Lower capital expenditures resulting from reduced peak demand improves asset utilization and results in customer bill savings. The customer engagement platform will be a forward looking "one-stop-shop" for everything customers related to the products, services and rate offerings available to them.

Data Sharing Platform

The Company's New Hampshire affiliate is working in collaboration with a broad range of stakeholders to develop the foundational components of an online energy data platform that can be implemented to provide benefits in equal measure to the Company's customers in Massachusetts. Two of these foundational components are at the core of this proposal as required by the enabling statute: (1) suitability for Green Button Alliance approval, and (2) the creation of and adherence to a "logical data model." There are numerous functional use cases of value to interested parties that warrant consideration for inclusion in options for platform design. Development of the unique functionality necessary to support the specific data and output for all desired outcomes would require an enormous and potentially unrealistic level of up-front design and requirements gathering, likely necessitating a traditional "Waterfall" style software development lifecycle. "Waterfall" projects – where project activities occur in linear, sequential phases – by their nature traditionally incur a much longer time-to-launch trajectory with all of the accompanying cost and obsolescence risks that can follow. In an attempt to avoid this, an "enabling platform" is proposed that securely provides a core set of customer energy usage and billing data points in a standardized data format. The Company refers to this architecture as a "Virtual Energy Data Platform".

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

The Company, along with the other EDCs, are working collaboratively with the AMI Stakeholder working group to discuss numerous issues, including data sharing. The group to date has been focused on the following aspects:

- Data Guiding Principles - Focused on 1) compliance with state laws, 2) data security best practices and 3) data strategies for individual customer, building-level and aggregated data
- Data Sharing Method – Focused on a common statewide solution for all EDCs, common platform for sharing information such as Green Button Connect, individual and aggregated data, and ability to manage multiple properties
- Data to be Share – Focused on the development of a logic data model and specifics about what data will be share and the interval of the data sharing
- When the Data is Available – Focused on when the data will be made available for use
- Timeline – Focused on when customer, aggregated and building-level data can be made available for use
- Vetting of Third-Parties – Focused the need to develop a process and procedure for vetting third-party users
- Customer Consent – Focused on the various considerations for consent associated with individual customer, building-level and aggregated data

This is an active stakeholder process as required through grid modernization. The final outcomes and details will be handled through that process.

The Company filed a concept paper through Federal Funding Opportunity Announcement DE-FOA-0002740 titled "BIL – Grid Resilience and Innovation Partnerships for it AMI Replacement project. The Company was encouraged to file a full grant application following review of the concept paper. The Company decided to delay a full grant application until 2024. The purpose for delaying the grant filing is to allow the Company to work collaboratively with the other EDCs and with utilities around New England to file a joint grant application.

6.3.2 Proposed Projects for 2025-2029 - Description of Implementation Justification and Expected Benefits

6.3.2.1 ENABLE DER TO PROVIDE GRID SERVICES

Project Summary - Develop and demonstrate a framework to compensate DER for providing locational grid services solutions, including mechanisms to increase the value of DER deployed in EJ communities. This investment area includes three components designed to ensure fair and equitable implementation.

- Grid Service Study (Joint EDC Study) - Engage a third-party consultant to support a study of the value of DER and load flexibility as a locational grid service. Building on work supported by the Mass CEC, the study would establish specific levels of compensation for locational grid services, considering the value they create in either capacity or voltage support use cases, depending on their level of availability and assuming direct utility visibility and control to ensure safe and reliable grid operations. The study would include provisions for the added value dispatchable DER can provide in underserved EJ communities. The study would also recommend process mechanisms to implement compensation framework based on minimizing implementation cost and increasing value to DER facilities. Unitil and the other Massachusetts EDCs are proposing to conduct the study collaboratively with input from stakeholders.

- Grid Service Compensation Fund - Establish a fund to compensate dispatchable DER and flexible loads participating in a program to allow utility dispatch to provide grid services. Dispatchable DER and flexible load with capacity to provide grid services would be eligible for compensation consistent with the recommendations from the Grid Service Study. Operating guidelines would ensure facilities were dispatched by the Company based on mutually agreed upon parameters that ensure no violation of interconnection agreements and provide clarity to customers on the impact to operational flexibility. Another consideration for implementation includes the interplay between participation in ISO-NE wholesale market versus distribution grid services.

- Transactional Energy Study (Joint EDC Study) - The EDCs are proposing to conduct the study collaboratively with input from stakeholders. Building upon learnings from the Grid Services Study, the Company proposes a second study together with the other EDCs to develop recommendations for a more dynamic locational value compensation framework. The study would be completed in the second half of the 2025-2029 term and would be based on results and lessons learned from implementation of the Grid Services Compensation Fund. The result of the Transactional Energy Study would inform proposals in the Company's 2030-2034 ESMP.

Payments made to participating facilities would be based on the value framework established in the Grid Services Study. Knowledge gained through the 2025-2029 ESMP demonstration period will inform future efforts to implement DER grid service programs at scale based on the optimal level of incentive to encourage participation, while minimizing costs to customers. The ability of the Company to implement this program assumes authorization to deploy the DERMS investment described below.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
O&M Costs (000s)	$ 200	$ 200	$ 50	$ 50	$ 50	**$ 550**
Total Costs (000s)	**$ 200**	**$ 200**	**$ 50**	**$ 50**	**$ 50**	**$ 550**

Table 33 – Proposed Grid Services Spending

The estimate for this project was developed assuming $150,000 in 2025 and $150,000 in 2026 for the Company's portion of the group study work and program development costs. In addition, there is $50,000 estimated in each year from 2025 to 2029 for incentive payments. The estimated incentive payments are based upon $100/MWh which translates to approximately 500 "events" where 1 MWh is saved.

Determining the proper level of compensation level for DER providing a grid service can be complex. The value of a DER is dependent on its reliability and availability to address a system constraint in the absence of a traditional wired solution. Electric utility dispatchers count on utility owned and maintained infrastructure to have very high levels of reliability and availability. Resources that are not owned and maintained by the utility may not have the same level of reliability and availability. Real time monitoring and control of these resources, as well as operating agreements, will be critical for these resources to provide a grid service that the electric utility can rely upon. The reliability and availability of a resource can be improved through diversity. For instance, if the resource is a VPP configuration with many individual DERs, the impact of any given DER not being available is less critical.

The value of a DER is also dependent upon the need the DER is addressing. Electric system resources and constraints change on a minute-by-minute and hour-by-hour basis. System configuration can change the value of a DER. This level of complexity should be considered in the design of the incentive.

The incentive mechanism developed needs to be flexible enough to address many different considerations, but simple enough to understand and execute.

Customer Benefits – The need to accommodate the load growth associated with beneficial electrification and further support for DER integration requires expansion of the capacity of the Company's distribution system. This infrastructure deployment will provide the grid flexibility required to ensure all customers have access to the benefits of clean energy. However, the full promise of grid modernization cannot be realized by investments in utility infrastructure alone.

Utilizing current and future clean energy DER as a grid asset is a critical component to the total solution, making use of all available resources to optimize the distribution grid for cost-effective clean energy deployment. Together, capacity upgrades supported by DER used to provide grid services ensure all tools in the tools box are utilized to meet the Commonwealth's aggressive clean energy objectives.

Currently, DER facilities are limited in their ability to receive compensation for benefits they may provide a distribution system "value stack" without a mechanism to provide locational grid services. To date, the promise of using dispatchable clean energy resources to create value has been limited to addressing system-wide needs such as ISO-NE peak. System needs, however, are highly locational, varying significantly by substation, feeder and even circuit segment. As a distributed resource, dispatchable DER can address local system needs by providing grid services to address capacity and voltage constraints. For example, if a substation transformer is at risk of an overload in the reverse direction (distribution to transmission) during light load periods, solar can be curtailed or batteries can be charged to alleviate the constraint. Similarly, to reduce line losses and associated carbon emissions, solar or battery inverter settings can be changed to support optimized power flows as a part of a Volt VAR optimization scheme.

The constraint limiting the ability of DER to provide grid services is partially technical. Existing systems and technologies need improvements to identify needs in real time, locate DER available to address the need, dispatch the resource in real time, ensure resource addresses the need once dispatched, and provide tracking of system operations. Assuming all the technology is in place, a mechanism is needed to compensate DER for allowing the utility to dispatch for local real time system conditions.

In addition to ensure resource availability, the level of value a DER resource can provide is also driven by the need the DER is addressing. Given the local and time-based nature of system need for capacity or voltage support, value is constantly changing. The trade-off between simplicity of incentive design and the accuracy of value determination must be considered.

Finally, the value of DER should take into consideration the added benefits of encouraging clean energy development in EJ communities. The concept of value stacking to include the use of DER as a grid asset can be expanded to include recognition of the incremental value of siting solar and other clean energy DER in areas historically disproportionately affected by the health and economic impacts of pollution.

The customer value of this investment is to demonstrate a scalable, cost-effective mechanism to capture the unrealized value of DER to provide locational grid services and transfer that value as incentives for further clean energy deployments, prioritizing economic and health benefits of focusing investments on EJ communities. The results of the learnings gained as a result of this investment will inform implementation on a wider scale, potentially using tariffs or other mechanisms, in the Company's 2030-2034 ESMP.

6.3.2.2 Grid Modernization – ADMS/DERMS

Project Description

The Company proposes to continue the deployment of ADMS and the other functionalities that it supports. 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.

Additionally, in 2026 with the installation of a new AMI system the Company plans evaluate "model-based" VVO to "meter-based" VVO. Meter-based VVO may provide the opportunity to deploy fewer line sensors as metering points and potentially allow for a more accurate model. 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.

In 2026 the Company plans to complete its implementation of the unbalanced loadflow and short circuit modules. This will fully enable ADMS to perform all FLISR, VVO and other loadflow required functions. Once complete additional devices will get added to these functions as they are deployed.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 0	$ 150	$ 75	$ 0	$ 0	**$225**
O&M Costs (000s)	$ 0	$ 188	$ 199	$ 211	$ 224	**$822**
Total Costs (000s)	**$ 0**	**$ 338**	**$ 264**	**$ 211**	**$ 224**	**$ 1,047**

Table 34 – Proposed ADMS/DERMS Spending

Customer Benefits

ADMS is an enabling technology. The ADMS will enable effective VVO, reducing customer energy consumption by 2% and commensurate peak demand reductions. The benefits will accrue directly to consumers as reductions in electricity bills, and through utilities as reductions in demand charges. The ADMS will also enable better voltage control for integration of DER and improved reliability through FLISR. The ADMS will serve as a platform for more advanced modules such as a DERMS. DERMS will provide the visibility and control needed to enable an increased quantity of distributed resources.

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 and network configuration. Additionally, the Company's ADMS will utilize "real-time" unbalanced load flow calculation results to automatically control distribution equipment for VVO.

Based upon recent history, FG&E experiences on average 1.5 circuit level outages per month which averages 2,000 customers. FG&E's average outage duration CAIDI is approximately 80 minutes. It is assumed that SCADA can reduce the length of the outage by 10 minutes (5 minutes at the front end and 5 minutes at the end of the outage). That savings would be 20,000 customer-minutes per circuit level outage or 30,000 customer minutes per month (20,000 customer minutes per outage * 1.5 circuit level outages per month) or 360,000 customer-minutes per year.

DERMS provides the ability to manage and control multiple DER facilities and other infrastructure (electric vehicle charging stations, demand response, 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.

6.3.2.3 Grid Modernization – VVO

Project Description

The Company proposes to continue the commissioning of VVO as described in the 2022-2025 Grid Modernization Plan. The VVO project will continue to install automated communications and controls on all voltage regulators, capacitor banks, energy measurement devices, as well as substation LTC's. The automation will be enabled through communications to the central ADMS system to optimize system voltage and power factor throughout the distribution system. Between 2025 and 2029, the plan is to enable VVO at seven additional substations.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 0	$ 4,574	$ 2,875	$ 3,092	$ 2,387	**$12,928**
O&M Costs (000s)	$ 0	$ 20	$ 23	$ 30	$ 33	**$121**
Total Costs (000s)	**$ 0**	**$ 4,594**	**$ 2,898**	**$3,112**	**$2,420**	**$13,049**

Table 35 – Proposed VVO Spending

Customer Benefits

The VVO system operates by constantly optimizing 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. This will directly benefit customers by reducing their electricity consumption and thereby reducing their bills. The Company's overall plan is to install VVO on 100% of the Company's circuits. Therefore, all customers will have the opportunity to achieve the benefits of VVO.

Year	Installation	Estimated Annual Energy Delivered (kWh)[27]	Annual Peak Load (MVA)	Estimated Annual Savings ($$)	Estimated Cumulative Annual Savings ($$)	Cumulative Demand Savings (MVA)	Cumulative Energy Savings (kWh)
2025	Townsend Summer ST. Lunenburg West Townsend	177,835,509	59	1,486,029	1,486,029	1.2	3,556,710
2026	Beech St.	39,928,166	12	333,648	1,819,677	1.4	4,355,274
2027	Pleasant St. Princeton Rd.	74,118,366	19	619,348	2,439,025	1.8	5,837,641
2028	Rindge Rd. Canton St. River St.	52,742,273	20	440,725	2,879,750	2.2	6,892,486
2029	Sawyer Passway	38,652,580	13	322,989	3,202,738	2.5	7,665,538

Table 36 - Estimate Annual VVO Savings

For this portion of the VVO project, the cumulative annual savings, at the completion of the project, are estimated to be approximately 2.5 MVA in peak demand, approximately 7.900,000 kWh in energy savings and approximately $3.0 million in bill savings. The savings calculated here are estimated annual savings assuming a 2% reduction in energy consumption multiplied by the current distribution and basic service rates. The savings in this chart are cumulative, so in 2026 the annual savings would total $1,819,766 ($1,486,029 + $333,648). The savings flow directly to customers through reductions in their monthly bills.

6.3.2.4 Grid Modernization – Automation

Project Description

The objective of this project is to implement key Automation functionality at the Company's remaining substations and extend monitoring and control out on the distribution system. There are currently reclosers and switches located out on the distribution system that require manual operation. Adding automation control of these devices will reduce the number of truck rolls and reduce outage time through the ability to remotely monitor and control the devices.

[27] Estimated Annual Energy Delivered is in 2022 Appendix 1 of the 2022 Grid Modernization Plan Annual report

This project includes adding Automation to 2 field sites per year.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 0	$ 100	$ 100	$ 100	$ 100	**$400**
O&M Costs (000s)	$ 0	$ 0	$ 0	$ 0	$ 0	**$0**
Total Costs (000s)	**$ 0**	**$ 100**	**$ 100**	**$ 100**	**$ 100**	**$ 400**

Table 37 – Proposed SCADA Automation Spending

Customer Benefits

In addition to facilitating the ADMS/OMS/VVO and other modernization projects, SCADA monitoring and control at the distribution level is foundational to reducing outage response and restoration times through improved outage awareness, fault location, isolation and system reconfiguration capabilities, both manually or through automation. After implementation, it is estimated that outages originating at SCADA-controlled devices may be reduced by 5 minutes of response time at the front-end and 5 minutes of re-energization time at the backend of an outage for a total savings of 10 minutes, in addition to the time saved with the ability to transfer load. Based upon an example outage effecting 1,500 customers, this would translate to a savings between 15,000 customer minutes per outage.

The following functionality is intended for the devices where these SCADA additions or modifications are planned:

- Real-time telemetry and historical interval data collection for each recloser, including the following measurements:
    - Voltage
    - Current
    - Active and Reactive Power
    - Active and Reactive Energy (where required)
- Remote monitoring of live/dead states of circuits
- Remote monitoring and control of included breakers, reclosers, switches, etc.

6.3.2.5 Grid Modernization – FERC Order 2222 Implementation

Project Summary - The goal of FERC Order 2222 is to modernize the electric grid and promote competition in the electric markets by removing the barriers preventing DERs from entering the market. The Order allows DERs to participate in the wholesale markets in the same manner that traditional capacity resources participate. This opens up the wholesale market to new sources of energy and grid services.

The Company recognizes that the final FERC 2222 guidelines are not yet approved, but anticipates modifications to software, control systems, other system upgrades may be required within the timeframe of this plan.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 100	$100	$ 0	$ 0	$ 0	**$ 0**
O&M Costs (000s)	$ 50	$ 50	$ 50	$ 50	$ 50	**$ 250**
Total Costs (000s)	**$ 150**	**$ 150**	**$ 50**	**$ 50**	**$ 50**	**$ 450**

Table 38 – Proposed FERC 2222 Spending

Customer Benefits - FERC Order 2222 will help to facilitate competition in the electric markets by removing barriers preventing DERs from competing on a level playing field in the organized capacity, energy and ancillary services markets run by regional grid operators. Over the last few years, DERs have become increasingly popular and desire to enter the wholesale marketplace to compete alongside traditional sources. DERs have the ability to reduce capacity constraints, integrate and increased amount of renewable energy resources, reduce GHG emissions, support the State energy policy, defer distribution investment, and allow customers take control of their own energy future.

6.3.2.6 Grid Modernization – Cyber Security

Operations Technology Cyber Security Enhancements

As Unitil upgrades its infrastructure, incorporates new technologies, and brings together Operational Technology and Information Technology networks, Operational Technology and Industrial Control Systems must be maintained and protected within modern, heterogeneous network environments.

In the next five years, the goal is to implement software solutions to provide improved visibility and actionable data for the many Unitil control system implementations, while simultaneously developing policies and procedures to effectively manage this work. The primary objective is to identify and catalog all assets in the Operational Technology environments, as well as any risks associated with them, and eliminate or mitigate those risks. Doing so will put Unitil in a better position to identify threats, both cyber and operational, such as:

- Cyberattacks (E.g. Denial of Service, Ransomware)

- Unauthorized network connections, communications
- Suspicious user behavior or policy changes
- Device malfunction or misconfiguration
- New and unresponsive assets
- Corrupted messages
- Unauthorized firmware downloads
- Insecure protocols
- Default credentials and insecure authentications
- Logic changes

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$21	$25	$28	$28	$28	**$130**
O&M Costs (000s)	$13	$13	$13	$14	$15	**$68**
Total Costs (000s)	**$34**	**$38**	**$41**	**$42**	**$43**	**$197**

Table 39 – Operations Technology Cybersecurity Spending

Information Technology Corporate Cyber Security Enhancements

The changing threat landscape, regulatory requirements, technology advancements and more in-depth assessment by cyber security insurance providers fuels the need to add new capabilities to Unitil's cyber defense toolbox.

New technology and innovation by nation-state adversaries and criminal enterprises has resulted in more diffuse, more sophisticated, and more dangerous cyber threats than ever before. Staying ahead of these advances requires that Unitil regularly re-assess security tools and deploy cutting-edge solutions tailored to our environment and risks.

In the next five years, Unitil plans to investigate and implement several upgraded programs and technologies to address these risks and strengthen our security posture. Projects include:

- Security Information and Event Management (SIEM) and Security Orchestration, Automation and Response (SOAR)
- Zero-Trust Architecture
- Privileged Access Management
- Network Access Control
- Static Code Analysis

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$84	$95	$70	$70	$70	**$389**
O&M Costs (000s)	$7	$7	$7	$7	$7	**$35**
Total Costs (000s)	**$91**	**$102**	**$77**	**$77**	**$77**	**$424**

Table 40 – Proposed Information Technology Cyber Security Spending

Customer Benefits

Cyber security of the system is of critical importance to the safety and reliability of the electric grid. More expansive deployment of technology and integration of Company networks with other systems increases the exposure to cyber security risks. Illustrative examples of those risks include direct control of field devices by unauthorized access or an altering of real-time information from the field to the central office resulting in an inaccurate evaluation of the current status of the grid. The reliable function of the Company's control systems (i.e. SCADA, DERMS, ADMS) is critical to public safety and reliability of the grid. Customers need to have confidence that the Company's computer networks are resilient against cyber-attacks. Data security and customer privacy must be carefully integrated into existing operational practices.

6.3.2.7 ESMP Program Administration

The administration of this proposed ESMP will be a considerable undertaking for the Company. At this point, the Company is proposing to implement this program primarily with internal resources to control the costs to customers. The funding shown below will be used for stakeholder outreach activities (including CESAG compensation as discussed in Section 3) and measurement and verification (similar to grid modernization).

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$0	$0	$0	$0	$0	**$0**
O&M Costs (000s)	$75	$75	$75	$75	$75	**$375**
Total Costs (000s)	**$75**	**$75**	**$75**	**$75**	**$75**	**$375**

Table 41 – ESMP Program Administration

6.4 10-YEAR PROJECTS

The electric system serves approximately 30,500 customers with an anticipated design peak load of 105.3 MW in 2025, increasing to 118.5 MW in 2034. This increase is predominantly due to proposed large customer load (approximately 3 MW) as well as forecasted EV and electrification load. As part of the Company's traditional electric system and distribution system planning efforts and additional review due to the additional EV and electrification load the electric system was evaluated at these ten-year load levels.

The ten-year load forecasts and planning efforts are updated and performed annually to identify project need and timing. The following subsections detail the system constraints and significant projects proposed as a result of the ten-year study process.

6.4.1 Identified Constraints

The following summarizes the system deficiencies driving improvement proposals during the ten-year study period, with the load level and projected year in which they first occur. The table is sorted by year. The system constraint is listed in the year when it first violates planning criteria.

Year	System Constraint	Circumstances
2025	Lunenburg S/S – 13.8kV Bus Regulators – Loaded Above Normal Rating	Basecase
2026	Lunenburg S/S – 31T1, 69kV-13.8kV, 10.5MVA Transformer – Loaded Above Normal Rating	Basecase
2030	08 Line – Pleasant Street S/S to Lunenburg S/S – Loaded Above Emergency Rating	N-1 – Loss of 09 Line from Summer Street to West Townsend
	09 Line – Pleasant Street S/S to Lunenburg S/S – Loaded Above Emergency Rating	N-1 – Loss of 08 Line from Summer Street to Townsend
2034	Flagg Pond S/S – 4T1, 115kV-69kV, 100MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of Flagg Pond 4T2
	Flagg Pond S/S – 4T2, 115kV-69kV, 100MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of Flagg Pond 4T1

Table 42 – System Constraints 2025-2034

6.4.2 Lunenburg Substation Capacity Additions - 2026

In-depth distribution planning efforts including distribution load forecasts, distribution circuit analysis (unbalanced loadflow modelling) and a detailed Lunenburg Area Study identified capacity and voltage constraints associated with Lunenburg substation and its 30W30 distribution circuit. To address these constraints at Lunenburg substation through 2030, the Company plans to increase the capacity of Lunenburg substation by installing a new 30MVA (or larger), 69kV to 13.8kV transformer with LTC. This will require the expansion of the Lunenburg substation. The expanded substation will be constructed to accommodate two 13.8 kV buses with three outgoing distribution circuit terminals per bus.

For the initial construction the new transformer will supply one 13.8 kV bus and will supply circuits 30W30 and 30W32 (new circuit) with the existing 10.5MVA supplying the other 13.8kV bus and circuit 30W31 and 30W33 (new circuit).

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 4,400	$ 4,700	$ 0	$ 0	$ 0	**$9,100**
O&M Costs (000s)	$ 0	$ 0	$ 0	$ 0	$ 0	**$0**
Total Costs (000s)	**$ 4,400**	**$ 4,700**	**$ 0**	**$ 0**	**$ 0**	**$9,100**

Table 43 – Proposed Lunenburg Substation Spending

This project is currently in the design phase with an expected completion date in 2026. Once complete this project is expected to address equipment loading associated with Lunenburg until approximately 2040. This project does not address loading or voltage constraints associated with the 30W30 distribution circuit, Flagg Pond substation, the 08 line or the 09 line.

Additional consideration and evaluation should be performed to determine if dual high-side (115kV x 69kV) voltage transformers should be purchased as the area of Lunenburg substation has been identified as a future 115kV substation location.

Loading on this equipment will continue to be reviewed on an annual basis and as needed upon new customer inquiries. Replacement timing of the existing 10.5MVA transformer and population of additional circuit positions will depend upon when loading on the substation no longer meets planning criteria.

The capacity additions at Lunenburg substation will increase the reliability of this portion of the system though providing additional capacity to serve the load as well as provide the opportunity for circuit modifications to reduce the overall size and customer exposure due to the reduced customer counts. The amount of the capacity addition has been informed by the Company's demand assessment described in Section 8. This ensures the capacity will be available to support electrification of transportation and building sectors as well as increase the hosting capacity for the integration of new DERs such as PV, ESS, wind or other.

This project is expected to increase the load serving capacity and hosting capacity at Lunenburg substation by approximately 15MW. This is based on planning criteria and the rating of the current FG&E mobile transformer in the event of the loss of the new 30MW transformer. However, this project does not increase the overall load serving capacity of the FG&E system or the 08/09 lines.

This project is not anticipated to require detailed transmission evaluations or transmission level investments. The Company provides the transmission service provider with 10-year peak load forecasts on an annual basis. It is Unitil's expectation and understanding that these load levels are included in annual transmission planning efforts. These load forecasts typically include the added load driving system improvements, such as this and project specific transmission studies are not typically needed for upgrades internal to the electric system that do not directly impact, extend and/or tap transmission infrastructure.

6.4.2.1 Description – Capacity and Reliability Needs

Based on 2050 load forecasts it is expected that the Lunenburg substation could be loaded to approximately 41MW by 2050. The load forecast takes into consideration load reducers (i.e. energy efficiency, PV production at peak, demand response, etc.). Two 30MVA transformers will provide sufficient capacity for the area beyond 2050 and also allow for the restoration of all load following a substation transformer outage without the need for the installation of a mobile substation and/or spare transformer.

Constructing the substation to accommodate four additional circuit positions over what exists today will provide sufficient capacity when populated to serve the area with traditional distribution equipment and provide sufficient capacity to allow for restoration switching for mainline faults.

6.4.2.2 Non-Wire Alternatives

According to the Company's Project Evaluation Procedure, a project of this scale/cost would typically necessitate the review of non-traditional alternatives if the constraint allowed for construction to start three to five years in the future. However, due to forecasted load additions, this project requires construction to begin prior to the three-year construction start threshold, and as such only traditional alternatives were considered as options to address the identified constraints. The Company is continually evaluating project needs and will continue to assess the viability of NWA solutions for suitable needs.

Based on distribution substation and circuit level forecasts and historical load cycles it is anticipated that NWAs would need to offset nearly 6MW of demand and up to 66MWh of energy over the course of a 24-hour period by 2026, increasing by approximately 10% each year thereafter will be needed to defer the tradition alternative. Additionally, the amount of DER required to meet the criteria above is likely to drive hosting capacity additions at Lunenburg Substation.

The value of a DER is dependent on its reliability and availability to address a system constraint in the absence of a traditional wired solution. Electric utility dispatchers count on utility owned and maintained infrastructure to have very high levels of reliability and availability. Resources that are not owned and maintained by the utility may not have the same level of reliability and availability. Real time monitoring and control of these resources, as well as operating agreements, will be critical for these resources to provide a grid service that the electric utility can rely upon. The reliability and availability of a resource can be improved through diversity. For instance, if the resource is a VPP configuration with many individual DERs, the impact of any given DER not being available is less critical.

The value of a DER is also dependent upon the need the DER is addressing. Electric system resources and constraints change on a minute-by-minute and hour-by-hour basis. System configuration can change the value of a DER.

The constraint limiting the ability of DER to provide grid services is partially technical. Existing systems and technologies need improvements to identify needs in real time, locate DER available to address the need, dispatch the resource in real time, ensure resource addresses the need once dispatched, and provide tracking of system operations. Assuming all the technology is in place, a mechanism is needed to compensate DER for allowing the utility to dispatch for local real time system conditions.

6.4.2.3 Traditional Alternatives

Due to the need date of the project and proposed location of the load, only variations of the proposed project were evaluated as alternatives to this constraint. These variations were all anticipated to be more-costly than the proposed option.

6.4.2.4 Alternative cost allocation approaches to interconnect battery storage projects

This project is driven by a large customer spot load three years in the future. Therefore, in line with the Company's Project Evaluation Procedure, there are no capital investment projects (CIPs) proposed or envisioned for standalone battery storage in this area of the system.

6.4.2.5 Equity and EJ outreach

The Company is aware that the location of substation projects may have an adverse impact on Environmental Justice communities. This project is not located in an EJ community, and thus the impact of the project (notwithstanding the benefits of the project) will have a minimal impact on such communities.

Stakeholder outreach for this project has not yet taken place. The Company intends to use the community engagement framework described in Section 3 as the Company implements this project.

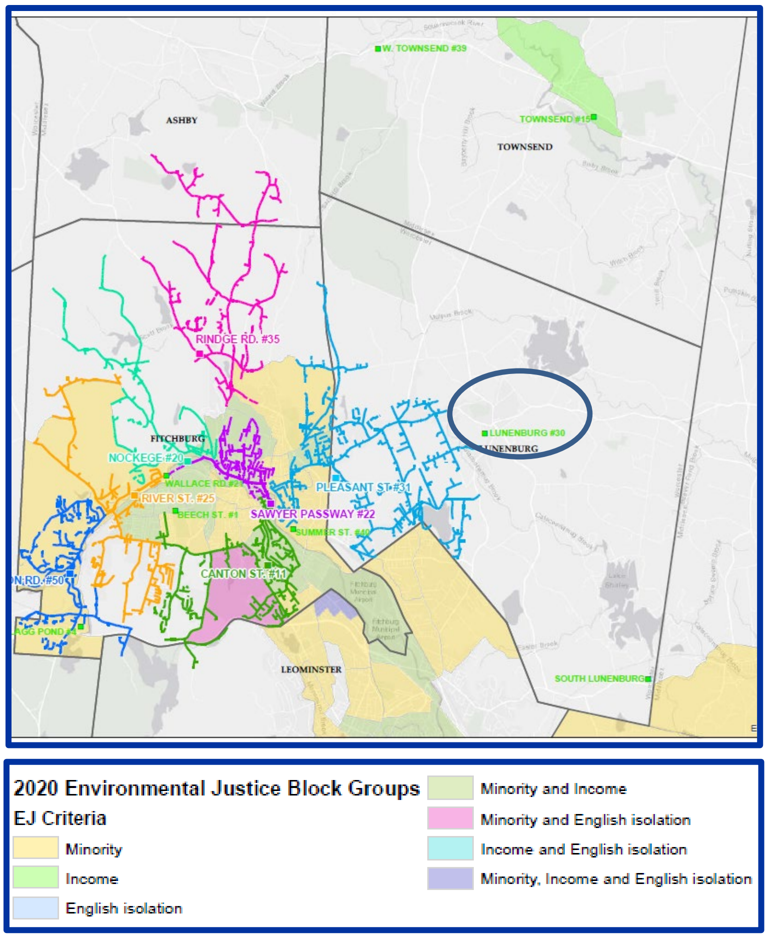

Figure 34 – Lunenburg Substation Location

6.4.3 New South Lunenburg Substation - 2030

In-depth distribution and system planning efforts including distribution load forecasts, distribution circuit analysis (unbalanced loadflow modelling), system balanced loadflow modelling and a detailed Lunenburg Area Study identified capacity constraints associated with Lunenburg substation, distribution circuit 30W30 and 08 and 09 lines. To address 08 Line, 09

Line and Lunenburg substation capacity constraints beyond 2030, the Company is in the early stages of exploring the feasibility of constructing a new 115kV or 69kV substation in southern Lunenburg. This project will require the purchase of a new plot of land in the vicinity of the existing National Grid right-of-way in southern Lunenburg near Leominster-Shirley Road. National Grid will tap the existing (or future upgraded) transmission system in the area to supply Unitil's new substation.

The proposed substation will consist of a 115kV, four position (two incoming transmission lines, two outgoing transformer taps) ring bus, two 30MVA (or larger), 115kVx69kV to 13.8kV transformers with LTCs, two 13.8 kV buses and six 13.8kV circuit positions. Three circuit positions will be populated and placed in-service when the substation is initially constructed with three circuit positions remaining vacant for future use.

Dual 115kV x 69kV transformers are currently being considered at this location as there are future plans for the existing 69kV lines in the area to be upgraded to 115kV.

Year	2025	2026	2027	2028	2029	Total Project Cost
Capital Costs (000s)	$1,750	$1,250	$7,000	$8,000	$2,500	**$20,500**
O&M Costs (000s)	n/a	$ 0	n/a	n/a	n/a	**n/a**
Total Costs (000s)	**$1,750**	**$1,250**	**$7,000**	**$8,000**	**$2,500**	**$20,500**

Table 44 – Proposed South Lunenburg Substation Spending

The Company is currently investigating available land in the area and has started initial discussions with National Grid regarding the transmission supply to the proposed substation. It is currently anticipated that the Company could have this substation in service in the 2029 timeframe with land procurement and detailed design work beginning in 2024.

This project is expected to remove approximately 10MW from the "greater" electric system and will defer the need to address Flagg Pond 4T1 and 4T2 transformer loading as well as 01, 02, 08, 09 line loading concerns to the following years. This project is anticipated to address loading and voltage constraints associated with the Lunenburg 30W30 distribution circuit and improve reliability to the customers served by the existing Lunenburg substation.

The new South Lunenburg substation is expected to increase both load serving capacity and hosting capacity of the FG&E system by approximately 30MW (load serving – approximately

10MW for Flagg Pond and 20MW at South Lunenburg, hosting capacity – approximately 3MW for Flagg Pond and 27MW at South Lunenburg).

Year	System Constraint	Circumstances
2037	Flagg Pond S/S – 4T1, 115kV-69kV, 100MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of Flagg Pond 4T2
	Flagg Pond S/S – 4T2, 115kV-69kV, 100MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of Flagg Pond 4T1
2040	01 Line – Flagg Pond S/S to Summer Street S/S – Loaded Above Emergency Rating	N-1 – Loss of 02 Line from Flagg Pond S/S to Summer Street S/S
	02 Line – Flagg Pond S/S to Summer Street S/S – Loaded Above Emergency Rating	N-1 – Loss of 01 Line from Flagg Pond S/S to Summer Street S/S
2043	08 Line – Pleasant Street S/S to Lunenburg S/S – Loaded Above Emergency Rating	N-1 – Loss of 09 Line from Summer Street to West Townsend
	09 Line – Pleasant Street S/S to Lunenburg S/S – Loaded Above Emergency Rating	N-1 – Loss of 08 Line from Summer Street to Townsend

Table 45 – Constraints Alleviated by South Lunenburg Substation

This project creates a new system supply into the Company's distribution system. The capacity additions at the New South Lunenburg substation will increase the reliability of this portion of the system though providing additional capacity to serve the load as well as provide the opportunity for circuit modifications to reduce the overall size and customer exposure due to the reduced customer counts. The amount of the capacity addition has been informed by the Company's demand assessment described in Section 8. The project will increase the hosting capacity of the overall area as it will reduce the loading on the 08 and 09 Lines as well as Flagg Pond Substation. This ensures the capacity will be available to support electrification of transportation and building sectors as well as increase the hosting capacity for the integration of new DERs such as PV, ESS, wind or other.

This project is expected to require detailed transmission evaluations and transmission level investments. Once the proposed location of the substation is identified the Company will submit transmission connection applications. ISO-NE and the transmission service provider will perform the necessary analysis to determine the level of transmission upgrades that will be required to support this project. This review will include the necessary analysis to confirm that the transmission system will have the capacity to adequately serve the proposed substation well into future. Additionally, depending on the final design of the substation it is currently assumed that the 69kV/115kV high-side bus and line breakers will be classified as transmission infrastructure.

The Company anticipates that once complete it will provide the transmission service provider with 10-year peak load forecasts on an annual basis for this new substation such that it will be included in on-going transmission planning efforts.

6.4.3.1 Description – Capacity and Reliability Needs

Based on 2050 load forecasts it is expected that the new South Lunenburg substation will be able to support load in the southern Lunenburg area until 2050 and beyond. The load forecast takes into consideration load reducers (i.e. energy efficiency, PV production at peak, demand response, etc.). It will have sufficient capacity to provide distribution circuit back-up to other circuits in the Lunenburg area. Additionally, the two 30MVA transformers will provide sufficient capacity for the area well beyond 2050 and also allow for the restoration of load following a substation transformer outage without the need for a 115kV to 13.8kV mobile transformer or the immediate installation of a spare transformer.

This project is also expected to improve reliability to the customers in served by the existing Lunenburg 30W30 circuit as well as circuit 30W31. Circuit 30W30 is historically one of the Company's worst performing circuits. This project will offload circuit 30W30, greatly reducing customer exposer as well as providing distribution circuit redundancy to the Lunenburg area. This project will also offer the opportunity to reconfigure circuits 30W31 to the 30W30 circuit position, reducing customer exposure on circuit 30W31.

6.4.3.2 Non-Traditional Alternatives

According to the Company's Project Evaluation Procedure, a project of this scale/cost would typically necessitate the review of non-traditional alternatives if the constraint allowed for construction to start three to five years in the future. However, due the project procurement, engineering and construction timeline of this project and its traditional alternatives, non-traditional alternatives were not considered. This project is currently under development and is expected begin prior to the three years typically needed to evaluate, install and confirm performance of a non-traditional alternative. The Company is continually evaluating project needs and will continue to assess the viability of NWA solutions for suitable needs.

Assuming the Lunenburg substation expansion project to address constraints through 2030 is complete it is anticipated that 1MW of demand and up to 12.5MWh energy over the course of a 24-hour period by 2030, increasing by approximately 0.5MW/6.5MWh each year thereafter will be required to defer the tradition alternative.

The value of a DER is dependent on its reliability and availability to address a system constraint in the absence of a traditional wired solution. Electric utility dispatchers count on utility owned and maintained infrastructure to have very high levels of reliability and availability. Resources that are not owned and maintained by the utility may not have the same level of reliability and availability. Real time monitoring and control of these resources, as well as operating agreements, will be critical for these resources to provide a grid service that the electric utility can rely upon. The reliability and availability of a resource can be improved through diversity. For instance, if the resource is a VPP configuration with many individual DERs, the impact of any given DER not being available is less critical.

The value of a DER is also dependent upon the need the DER is addressing. Electric system resources and constraints change on a minute-by-minute and hour-by-hour basis. System configuration can change the value of a DER.

The constraint limiting the ability of DER to provide grid services is partially technical. Existing systems and technologies need improvements to identify needs in real time, locate DERs available to address the need, dispatch the resource in real time, ensure resource addresses the need once dispatched, and provide tracking of system operations. Assuming all the technology is in place, a mechanism is needed to compensate DER for allowing the utility to dispatch for local real time system conditions.

6.4.3.3 Traditional Alternatives

The following group of traditional projects were considered as an alternative to the construction of the proposed South Lunenburg substation. All projects listed below would be required to address the identified constraints.

<u>08 and 09 Line Capacity Additions -2030</u>

Reconductor the 08 and 09 lines from Pleasant Street substation to the Lunenburg tap with 795 ACSR conductor (or larger).

These lines would be constructed in a “double-circuit” configuration to accommodate future 115kV transmission lines (one each pole) for future lines between Flagg Pond and Lunenburg substations in the future.

Year	2028	2029	2030	Total Project Cost
Capital Costs (000s)	$1,100	$4,950	$4,950	**$11,000**
O&M Costs (000s)	n/a	n/a	n/a	**n/a**
Total Costs (000s)	$1,100	$4,950	$4,950	**$11,000**

Table 46 – Estimated 08/09 Line Reconductoring

Flagg Pond Substation Capacity Additions - 2034

Installation of additional capacity at Flagg Pond. This would include the installation of an additional transformer or the replacement of the existing Flagg Pond transformers. At this time, it would be recommended that the existing transformers (including the system spare transformer) be replaced with new 200MVA units with LTCs. It is anticipated that voltage regulations will be required at Flagg Pond prior to 2050 and the additional capacity will address other future loading constraints. This project will also include the upgrade of the 69kV bus and breakers to accommodate the additional transformer and line capacity.

Year	2032	2033	2034	Total Project Cost
Capital Costs (000s)	$4,875	$9,750	$4,875	**$19,500**
O&M Costs (000s)	n/a	n/a	n/a	**n/a**
Total Costs (000s)	$4,875	$9,750	$4,875	**$19,500**

Table 47 – Estimated Flagg Pond Capacity Additions

Total Alternative Capital Costs (000's):

Year	2028	2029	2030	2031	2032	2033	2034	Total Project Cost
Flagg Pond Capacity Additions	n/a	n/a	n/a	n/a	$4,875	$9,750	$4,875	**$19,500**
08 & 09 Line Capacity Additions	$1,100	$4,950	$4,950	n/a	n/a	n/a	n/a	**$11,000**
Total Costs	$1,100	$4,950	$4,950	n/a	$4,875	$9,750	$4,875	**$31,500**

Table 48 – Estimated 08/09 Line and Flagg Pond Spending

6.4.3.4 Alternative cost allocation approaches to interconnect battery storage projects

Construction for this project is scheduled to begin within a five-year timeframe. Therefore, in line with the Company's Project Evaluation Procedure, there are no capital investment projects (CIPs) proposed or envisioned for standalone battery storage in this area.

6.4.3.5 Equity and EJ outreach

The Company is aware that the location of substation projects may have an adverse impact on Environmental Justice communities. This project is not located in an EJ community, and thus the impact of the project (notwithstanding the benefits of the project) will have a minimal impact on such communities.

Stakeholder outreach for this project has not yet taken place. The Company intends to use the community engagement framework described in Section 3 as the Company engages the community in this project.

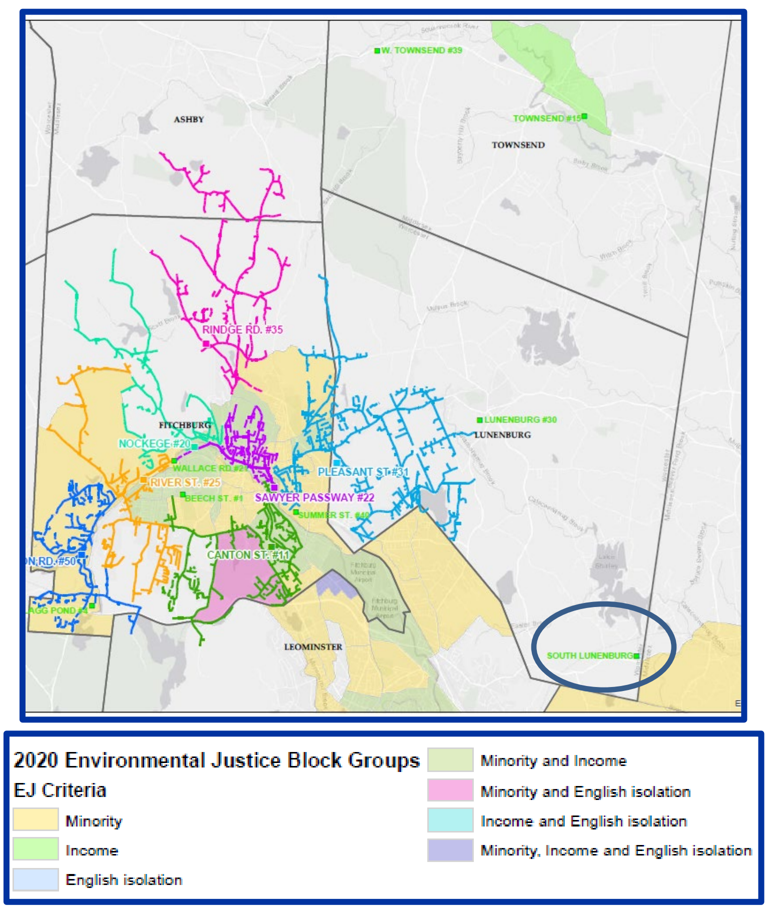

Figure 35 – South Lunenburg Substation Location

6.5 NEW CLEAN ENERGY CUSTOMER SOLUTIONS

DER penetration across the electric system continues to increase at a rapid pace. DERs are electricity producing resources or controllable loads connected to a distribution system, including but not limited to roof top solar, wind, CHP, energy storage, small gas-powered backup generators, electric vehicles, heat pumps and controllable loads. Behind the meter DER such as roof top solar is the largest application of DER technology across Unitil's service territory. Inefficient performance increases the risk profile for these DERs creating the need to optimize the system to ensure reliability. Hosting capacity and locational value analysis support the interconnection of DERs which provide an additional means of support for an optimized system.

The tables below provide the 2050 peak load and DER forecast with and without the system modifications as described throughout this report.

Substation	Transformer	No Changes				
		Nameplate (MVA)	2050 Peak Load (MW)	% Loaded of Nameplate	DER (MW)	% DER of Nameplate
Beech Street	1T1	22	47.7	213%	31.6	141%
Canton Street	11T1	14	26.2	187%	17.4	124%
Lunenburg	30T1	10.5	36.3	346%	24.1	229%
	30T2	n/a	n/a	n/a	n/a	21.7
Pleasant Street	31T1	14	36.8	263%	24.4	174%
Princeton Road	50T2	20	15.7	79%	10.4	52%
	50T3	20	47.9	239%	31.8	159%
River Street	25T1	14	26.3	188%	17.4	125%
Sawyer Passway	22T1	20	13.6	68%	9.0	45%
	22T2	20	9.8	49%	6.5	32%
Summer Street	40T1	35	59.2	169%	39.3	112%
	40T2	n/a	n/a	n/a	n/a	22.2
Townsend	15T1	10.5	33.3	317%	22.1	211%
	15T2	n/a	n/a	n/a	n/a	16.7
West Townsend	39T1	10.5	29.7	283%	19.7	188%
South Lunenburg	T1	n/a	n/a	n/a	n/a	11.8
	T2	n/a	n/a	n/a	n/a	11.8
Beech Street Tap	T1	n/a	n/a	n/a	n/a	17.5
	T2	n/a	n/a	n/a	n/a	10.5
Rindge Road	T1	n/a	n/a	n/a	n/a	n/a
Ashby	T1	n/a	n/a	n/a	n/a	12.0
	T2	n/a	n/a	n/a	n/a	16.9
Flagg Pond	4T1	100	194.6	195%	129.1	129%
	4T2	100	187.9	188%	124.6	125%
Lunenburg/Summer Supply	T1	n/a	n/a	n/a	n/a	n/a
	T2	n/a	n/a	n/a	n/a	n/a

Table 49 – 2050 Peak Load and DER Forecast – Without Proposed System Modifications

Substation	Transformer	2050 Proposed Changes				
		Nameplate (MVA)	2050 Peak Load (MW)	% Loaded of Nameplate	DER (MW)	% DER of Nameplate
Beech Street	1T1	22	16.2	72%	10.7	48%
Canton Street	11T1	30	21.0	70%	13.9	46%
Lunenburg	30T1	30	18.8	63%	12.5	42%
	30T2	30	22.8	76%	15.1	50%
Pleasant Street	31T1	30	23.6	79%	15.6	52%
Princeton Road	50T2	20	15.7	79%	10.4	52%
	50T3	30	24.0	80%	15.9	53%
River Street	25T1	30	16.6	55%	11.0	37%
Sawyer Passway	22T1	20	14.3	71%	9.5	47%
	22T2	20	10.3	51%	6.8	34%
Summer Street	40T1	30	23.3	78%	15.5	52%
	40T2	30	23.3	78%	15.5	52%
Townsend	15T1	30	17.5	58%	11.6	39%
	15T2	30	17.5	58%	11.6	39%
West Townsend	39T1	30	12.0	40%	8.0	27%
South Lunenburg	T1	30	12.4	41%	8.2	27%
	T2	30	12.4	41%	8.2	27%
Beech Street Tap	T1	30	18.4	61%	12.2	41%
	T2	30	11.0	37%	7.3	24%
Rindge Road	T1	30	21.3	71%	14.1	47%
Ashby	T1	30	12.6	42%	8.4	28%
	T2	30	17.7	59%	11.7	39%
Flagg Pond	4T1	200	109.5	55%	72.7	36%
	4T2	200	105.7	53%	70.1	35%
Lunenburg/Summer Supply	T1	200	83.6	42%	55.5	28%
	T2	200	83.6	42%	55.5	28%

Table 50 – 2050 Peak Load and DER Forecast – with Proposed System Modifications

The proposed system modifications will increase the total system hosting capacity by approximately 250%.

Unitil implements a standard criteria to evaluate NWAs to ensure the Company is considering alternatives to traditional utility investment. The Company's Project Evaluation Procedure (No. PR-DT-DS-11 Revision 1, dated 7/2/2021), provides a consistent approach and procedure for project evaluation and establishes thresholds in which the Company reviews non-wires alternative projects and performs detailed cost/benefit analyses that include reliability, environmental and economic impacts.

A good example of a recent NWA is the Company's Townsend Energy Storage System. The Company owns and operates a 2 MW/4MWh utility scale energy storage system located at Townsend substation designed to defer the need for a costly substation expansion. The energy storage system has the ability to serve over 1,300 homes for over two hours. This energy storage system is designed to reduce peak loading on the substation equipment, as well as provide voltage regulation and frequency regulation to the market. This is a significant size energy storage device measuring over 2% of the Company's system peak. The Company continues to evaluate opportunities to install additional utility scale energy storage in areas of the system that may benefit from the additional capacity.

The clean energy programs offered through the Mass Save 3- Year Plan include: energy efficiency, demand response (including battery storage), electric heat pumps and electric vehicles. Energy efficiency is used as an NWA to defer investment, as described in the Company's distribution planning guide. Through the Mass Save 3-Year Plans, targeted EE and load curtailment projects are reviewed for any major piece of equipment that is expected to exceed either of the following:

- Normal/Basecase Conditions - 80% of its seasonal normal rating during the first five years of the study period and 90% of its seasonal normal rating in year five of the study period.
- Planned Contingency Conditions - 100% of its seasonal normal rating during the first five years of the study period and 110% of its seasonal normal rating in year five of the study period or 80% of its seasonal LTE rating during the first five years of the study period and 90% of its seasonal LTE rating in year five of the study period.

To support the development of NWAs and enable DER to provide grid services, the Company has proposed the Grid Services Study (Joint EDC Proposal), Grid Service Compensation Fund, and the Equitable Transactional Energy Study (Joint EDC Study) (reference Section 6.3.2.1).

The Company's AMI system has been providing benefits to our customers for more than a decade. AMI provides the basis for interval metering which supports the rate programs to support demand response programs and further integration of renewable resources. The Metering Data Management system provides the platform for sharing data with customers and interested third parties and will enable time-based rates. Interval metering allows customers to manage their own risks and benefits. Advanced metering functionality is proven and a required component to develop the modern grid as an enabling platform.

Smart inverter technology continues to improve which will allow for further monitoring and control of DERs and renewable resources. Smart inverters will play a key role in the further deployment of DERs on the system in a safe and reliable manner.

Rate design is an important tool to shave peak loads. The Company has implemented TOU rates for electric vehicles and has the capability to develop other TOU programs. TOU rates benefit the customer as well as the system. Consumers with TOU rates and the ability and willingness to shift some usage to off peak hours not only benefit the customer through reduced rates, but it also benefits the system by reducing peak demand and deferring increases in capacity. TOU rates support demand response programs and other energy management activities that rely on automation to reduce their electricity consumption at peak times.

7 5-YEAR ELECTRIC SECTOR MODERNIZATION PLAN

The Company has taken a practical approach to the 5- and 10-year spending plans associated with this ESMP. This Plan has been developed based upon the Company's relative size and customer demographics. The Company will continue to review and modify this Plan as appropriate.

7.1 INVESTMENT SUMMARY 5-YEAR CHART – BASE RELIABILITY, EXISTING PROGRAMS, AND NEW PROPOSALS. IMPACT ON GHG EMISSION REDUCTIONS

The spending shown below considers existing capital and operating expense spending programs (base budget), pre-authorized programs (i.e. EE, grid modernization, and electric vehicles), and newly proposed spending (i.e. capacity, extended grid modernization, reliability and resiliency and customer facing programs).

It is Company's intention to seek from the Department approval of the proposed new ESMP spending in this plan and to allow for recovery incremental ESMP costs that through its Grid Modernization Factor that would not otherwise be recovered through existing cost-recovery mechanisms. If the Department approves the Company's ESMP, the Company will propose to recover the costs of these incremental ESMP investments and expenses through a future Grid Modernization Factor tariff filing.

The chart and table below identify the capital spending by category for the 2025 -2029 investments that are existing or previously approved investments.

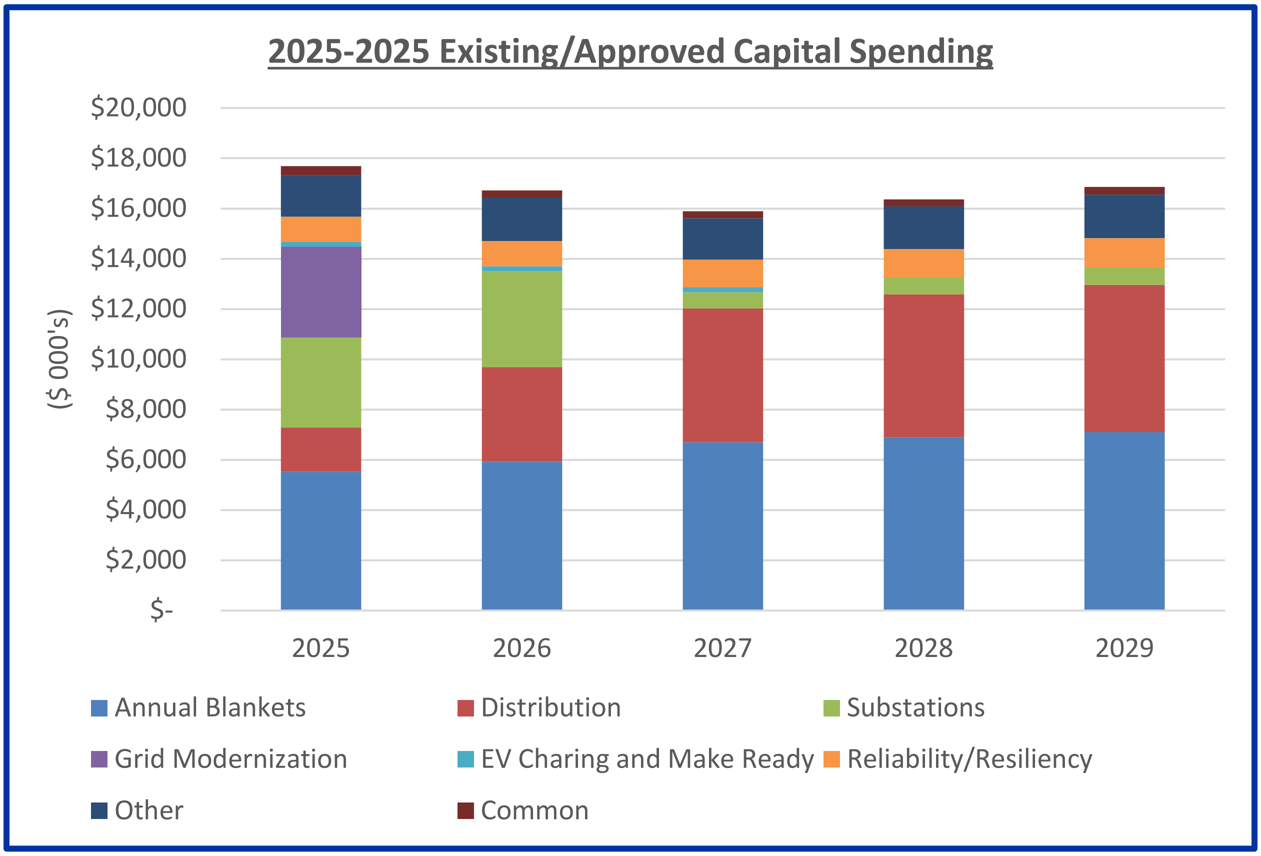

Figure 36 – 2025-2029 Capital Spending (Existing and Approved)

Category	2025	2026	2027	2028	2029
Annual Blankets	$ 5,522	$ 5,924	$ 6,695	$ 6,896	$ 7,103
Distribution	$ 1,760	$ 3,771	$ 5,324	$ 5,686	$ 5,856
Substations	$ 3,587	$ 3,811	$ 655	$ 675	$ 695
Grid Modernization	$ 3,608	$ -	$ -	$ -	$ -
EV Charing and Make Ready	$ 196	$ 196	$ 196	$ -	$ -
Reliability/Resiliency	$ 1,000	$ 1,000	$ 1,100	$ 1,133	$ 1,167
Other	$ 1,661	$ 1,741	$ 1,640	$ 1,689	$ 1,739
Common	$ 359	$ 280	$ 283	$ 291	$ 300
Total	$ 17,692	$ 16,723	$ 15,893	$ 16,370	$ 16,861

Table 51 – 2025-2029 Capital Spending (Existing and Approved) ($ 000's)

The chart and table below identify the capital spending by category for the 2025-2029 investments that are proposed or incremental ESMP investments.

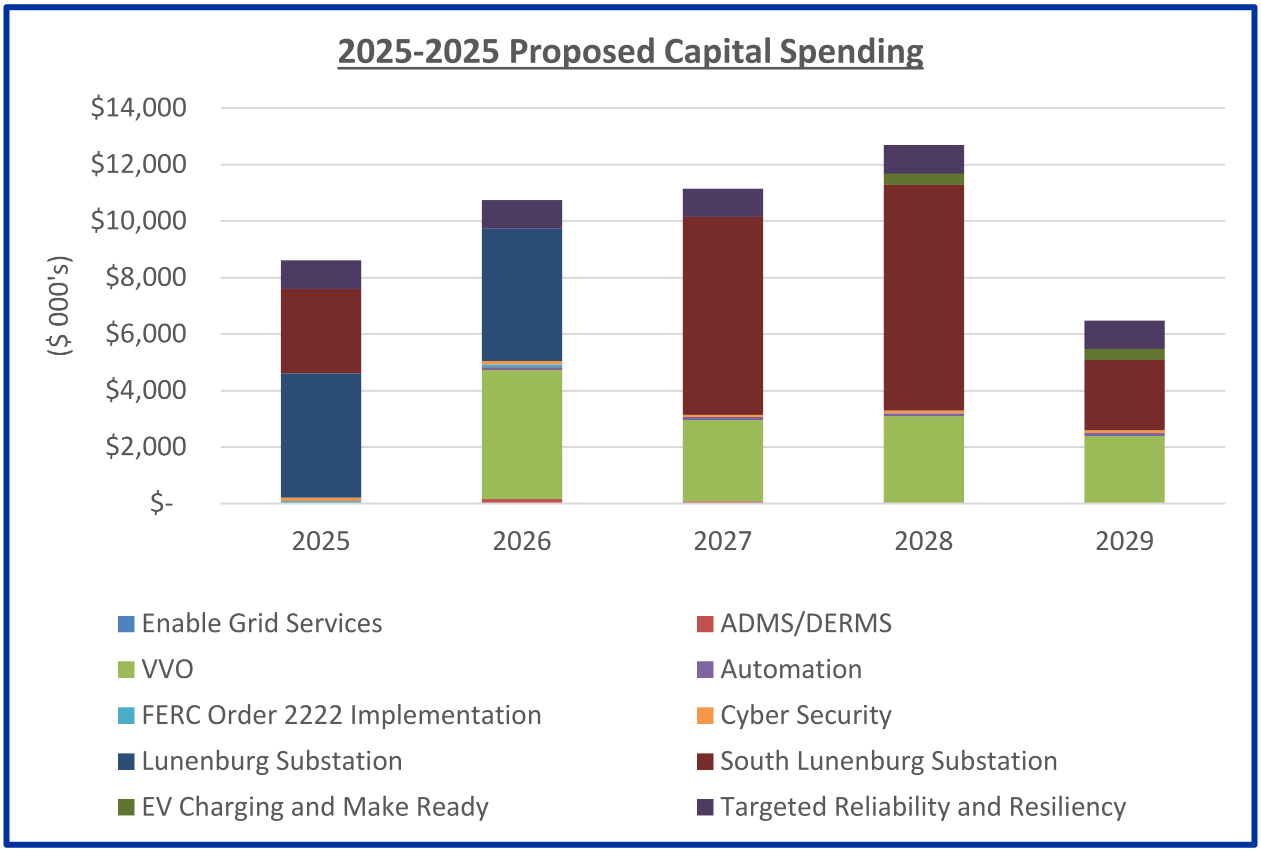

Figure 37 – 2025-2029 Capital Spending (Proposed)

Category	2025	2026	2027	2028	2029
Enable Grid Services	$ -	$ -	$ -	$ -	$ -
ADMS/DERMS	$ -	$ 150	$ 75	$ -	$ -
VVO	$ -	$ 4,574	$ 2,875	$ 3,092	$ 2,387
Automation	$ -	$ 100	$ 100	$ 100	$ 100
FERC Order 2222 Implementation	$ 100	$ 100	$ -	$ -	$ -
Cyber Security	$ 105	$ 120	$ 98	$ 98	$ 98
Lunenburg Substation	$ 4,400	$ 4,700	$ -	$ -	$ -
South Lunenburg Substation	$ 3,000	$ -	$ 7,000	$ 8,000	$ 2,500
EV Charging and Make Ready	$ -	$ -	$ -	$ 396	$ 396
Targeted Reliability and Resiliency	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000
Total	$ 8,605	$ 10,744	$ 11,148	$ 12,686	$ 6,481

Table 52 – 2025-2029 Capital Spending (Proposed) ($ 000's)

The chart and table below identify the existing and proposed capital spending for the 2025-2029 investments.

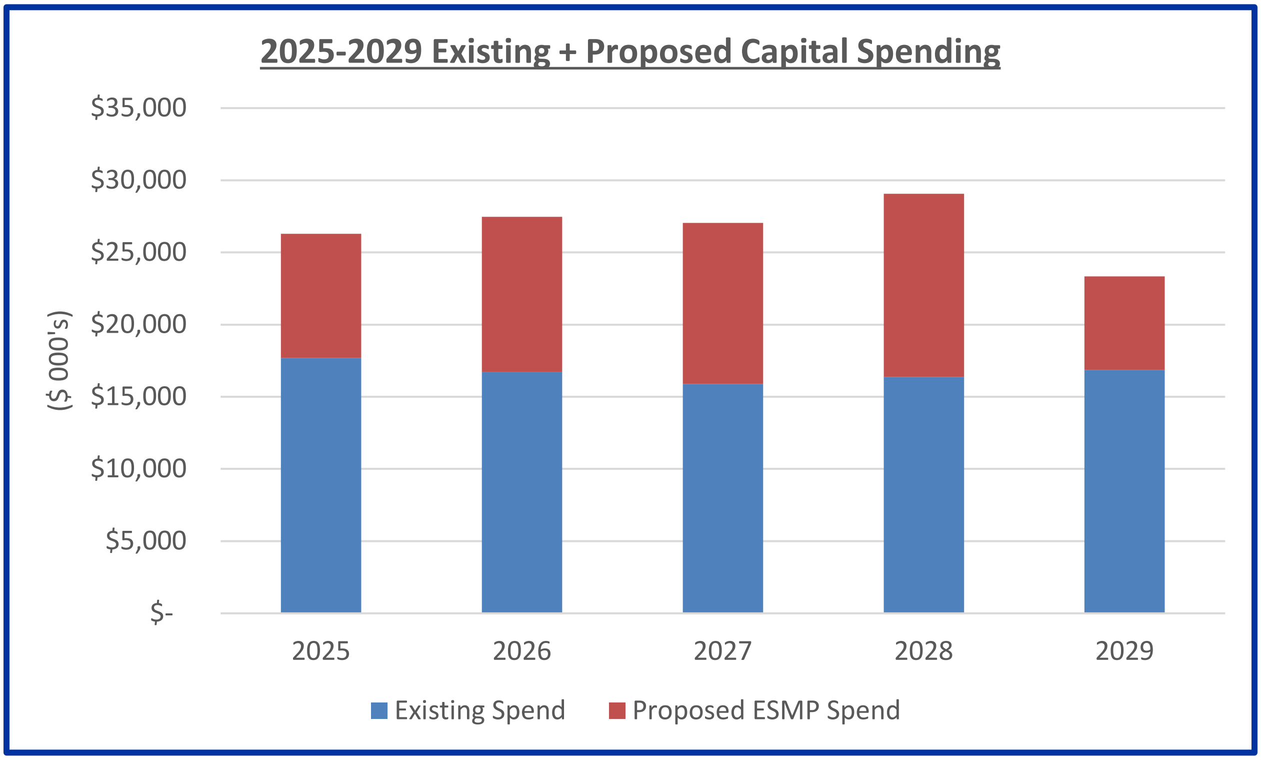

Figure 38 – 2025-2029 Capital Spending (Existing/Approved and Proposed)

Category	2025	2026	2027	2028	2029
Existing Spend	$ 17,692	$ 16,723	$ 15,893	$ 16,370	$ 16,861
Proposed ESMP Spend	$ 8,605	$ 10,744	$ 11,148	$ 12,686	$ 6,481
Total	$ 26,297	$ 27,467	$ 27,041	$ 29,056	$ 23,342

Table 53 – 2025-2029 Capital Spending (Existing/Approved and Proposed) ($ 000's)

The capital budget has been categorized as follows:

Existing Capital Spending:

- Annual Blankets - This category includes blanket authorizations for categories of projects where each individual project is small in value (under $30,000) and cannot be individually anticipated at budget time. As we previously explained, these projects are budgeted and authorized under a single blanket authorization representing the anticipated aggregate level of spending. The categories are generally self-explanatory. For example, distribution improvements include: minor upgrades and replacements and repairs to the distribution system; new customer additions consist of new customer requests for service including new services and small line extensions; outdoor lighting includes repairs and replacements of existing street lights and customer lighting fixtures; emergency and storm restoration includes capital repairs and replacements required to restore service to customers following storms or outages; billable work includes customer projects, pole accidents, cable TV projects and other projects where all or a portion of the work is billable; and, lastly, transformer and meters are for the purchase of transformers and meters.

- Distribution - These projects are individually authorized projects involving capital additions where the value of the project exceeds the maximum threshold allowed under blanket authorizations. The projects are generally self-explanatory. For example, overhead and underground line extensions are new extensions of primary facilities required to provide service to customers; street light projects are new projects to add street lighting; telephone company requests include pole replacements and relocations required under our agreements with Verizon or other pole attachees; highway projects are typically line relocations driven by state or municipal roadway projects; distribution and sub-transmission poles replacements include costs associated with replacing poles that failed inspection during the Company's 10-year pole inspection program; and, specific projects are all other projects in excess of $30,000 that are identified by engineering or others that are needed to meet service obligations.
- Substations - These are individually-authorized projects involving projects and capital additions to distribution substations. Each project is individually budgeted and authorized. The projects are typically identified by engineering, though the projects may also be identified as the result of inspection and maintenance activities.
- Reliability/Resiliency – These are projects designed and justified specifically to address reliability and resiliency concerns across the system. Projects are developed as part of the annual reliability planning process.
- Others - Communications includes additions and replacements of communication-related equipment such as Supervisory Control and Data Acquisition (SCADA), radio systems for field communications, and communication equipment for the Company's Advanced Metering Infrastructure (AMI) system; tools, shop, and garage includes most tools and test equipment used by electrical workers in the performance of their job; laboratory includes test equipment used to test meters and other devices.
- Common - Projects that can be allocated to both electric and gas are identified as common projects. These projects include office furniture and office equipment, including normal additions and replacements; and structures includes upgrades and improvements to the Company's buildings, including the Company's operations center building. Common facilities have been apportioned to electric or gas based on an allocation provided by Accounting. In general, these facilities represent only a small portion of the overall budget.

Pre-Authorized Capital Spending:

- Grid Modernization - These are individually-authorized projects that have received pre-authorization under the Company's filed Grid Modernization Plan._This was previously approved in DPU 15-121 and DPU 21-82.
- EV Charging and Make Ready – This is the pre-approved capital spending for EV charging make ready projects. The Department approved a five-year budget in Docket DPU 21-92.

Proposed or Incremental Capital Spending:

- Grid Modernization - These are new grid modernization projects proposed as part of this ESMP. These projects may be extensions or acceleration of existing grid modernization projects or programs. These projects include:
    - ADMS/DERMS - The Company proposes to continue the deployment of ADMS and the other functionalities that it supports. 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. In 2026 the Company plans to complete its implementation of the unbalanced loadflow and short circuit modules. This will fully enable ADMS to perform all FLISR, VVO and other loadflow required functions. It is currently anticipated that DERMS will be available to customers in 2027.
    - VVO - The Company proposes to continue the commissioning of VVO as described in the 2022-2025 Grid Modernization Plan. The VVO project will continue to install automated communications and controls on all voltage regulators, capacitor banks, energy measurement devices, as well as substation LTC's. The automation will be enabled through communications to the central ADMS system to optimize system voltage and power factor throughout the distribution system. Between 2025 and 2029, the plan is to enable VVO at seven additional substations.
    - Automation - The objective of this project is to implement key Automation functionality at the Company's remaining substations and extend monitoring and control out on the distribution system. There are currently reclosers and switches located out on the distribution system that require manual operation. Adding automation control of these devices will reduce the number of truck rolls and reduce outage time through the ability to remotely monitor and control the devices.
    - FERC Order 2222 Implementation - The goal of FERC Order 2222 is to modernize the electric grid and promote competition in the electric markets by removing the

barriers preventing DERs from entering the market. The Order allows DERs to participate in the wholesale markets in the same manner that traditional capacity resources participate. This opens up the wholesale market to new sources of energy and grid services. The Company recognizes that the final FERC 2222 guidelines are not yet approved, but anticipates modifications to software, control systems, other system upgrades may be required within the timeframe of this plan.

  - Cyber Security - The goal is to implement software solutions to provide improved visibility and actionable data for the many Unitil control system implementations, while simultaneously developing policies and procedures to effectively manage this work. The primary objective is to identify and catalog all assets in the Operational Technology environments, as well as any risks associated with them, and eliminate or mitigate those risks. In the next five years, Unitil plans to investigate and implement several upgraded programs and technologies to address these risks and strengthen our security posture.

- <u>Network Investments</u>
  - Lunenburg Substation - The capacity additions at Lunenburg substation will increase the reliability of this portion of the system though providing additional capacity to serve the load as well as provide the opportunity for circuit modifications to reduce the overall size and customer exposure due to the reduced customer counts. The amount of the capacity addition has been informed by the Company's demand assessment described in Section 8. This ensures the capacity will be available to support electrification of transportation and building sectors as well as increase the hosting capacity for the integration of new DERs such as PV, ESS, wind or other.
  - South Lunenburg Substation - This project creates a new system supply into the Company's distribution system. The capacity additions at the New South Lunenburg substation will increase the reliability of this portion of the system though providing additional capacity to serve the load as well as provide the opportunity for circuit modifications to reduce the overall size and customer exposure due to the reduced customer counts. The amount of the capacity addition has been informed by the Company's demand assessment described in Section 8. The project will increase the hosting capacity of the overall area as it will reduce the loading on the 08 and 09 Lines as well as Flagg Pond Substation. This ensures the capacity will be available to support electrification of transportation and building sectors as well as increase the hosting capacity for the integration of new DERs such as PV, ESS, wind or other.

- EV Charging and Make Ready – This is a proposed extension of the EV make ready program for the years 2028 and 2029 which were not previously approved in Docket DPU 21-92.
- Targeted Reliability/Resiliency – The Company is proposing to incrementally increase investment on targeted spacer cable and undergrounding projects by $1.0 million per year in an effort to increase the overall resiliency of the electric system. This level of funding will support the installation of approximately 2 miles of spacer cable or 700 to 1,800 feet of targeted undergrounding. This spending may also be used for developing circuit ties where they do not exist or automating circuit ties where they do exist. The Company is proposing to recover this amount with the ESMP incremental investments, while the existing reliability spending would be recovered with its core spending as part of a base rate case.

In an effort to provide a consistent view and categorization of the proposed capital spending, the Company has provided the table below which categorizes the investments, provides a summary of each category, describes where the cost of the investment category are recovered and provides the 2025-2029 capital spending.

Category	Summary	Recovery	2025-2029 Capital Spending
Core Capital	Programs to support safe and reliable service, including equipment repair, new customer connections, peak load growth, maintaining reliability in line with Service Quality metrics	Base rate case	$79.3M
CIP	Substation and line upgrades to enable DER interconnections with cost allocation	Individual projects filed with DPU	N/A
AMI	Deployment of meters, supporting technology, customer data sharing, outreach	Grid Mod Factor (through 2028)	$0.4M
Solar	Utility-owned solar and energy storage in applications that support community climate resilience	Individual projects filed with DPU	N/A – previously installed
Grid Mod	Technologies to increase grid visibility and control, integrate DER and support peak demand reduction	Grid Mod Factor (through 2025)	$3.6M
EV Program	Deployment of EV make-ready and charging infrastructure	EV Tracker (through 2027)	$0.6M
Customer Investments (VPP Enablement)	Platform technologies, customer compensation fund demonstration and studies to advance VVP programs for DER as grid assets, customer portals	INCREMENTAL ESMP	$0.2M
Platform Investments	ADMS/DERMS, billing capabilities to support time varying rates, cybersecurity, telecommunications, intelligent data capture	INCREMENTAL ESMP	$0.7M
Network Investments	New substation and distribution line upgrades to support electrification load growth and DER interconnections, VVO	INCREMENTAL ESMP	$42.5M (Substations $29.6M) (VVO $12.9M)
Resiliency	Undergrounding, reconductoring and other storm hardening infrastructure upgrades	INCREMENTAL ESMP	$5.0M
CIP	Substation and line upgrades to enable DER interconnections with cost allocation	INCREMENTAL ESMP	N/A
EV Infrastructure	Continuation of existing EV make ready and charging infrastructure enablement programs	INCREMENTAL ESMP (2028 and 2029)	$0.8M

Table 54 – 2025-2029 Existing/Approved + Incremental ESMP Capital Spending

In addition to capital investments, the Company has provided existing, previously authorized and proposed operations and maintenance expense spending. The chart and table below identify the O&M spending by category for the 2025-2029 investments that are existing or previously approved investments.

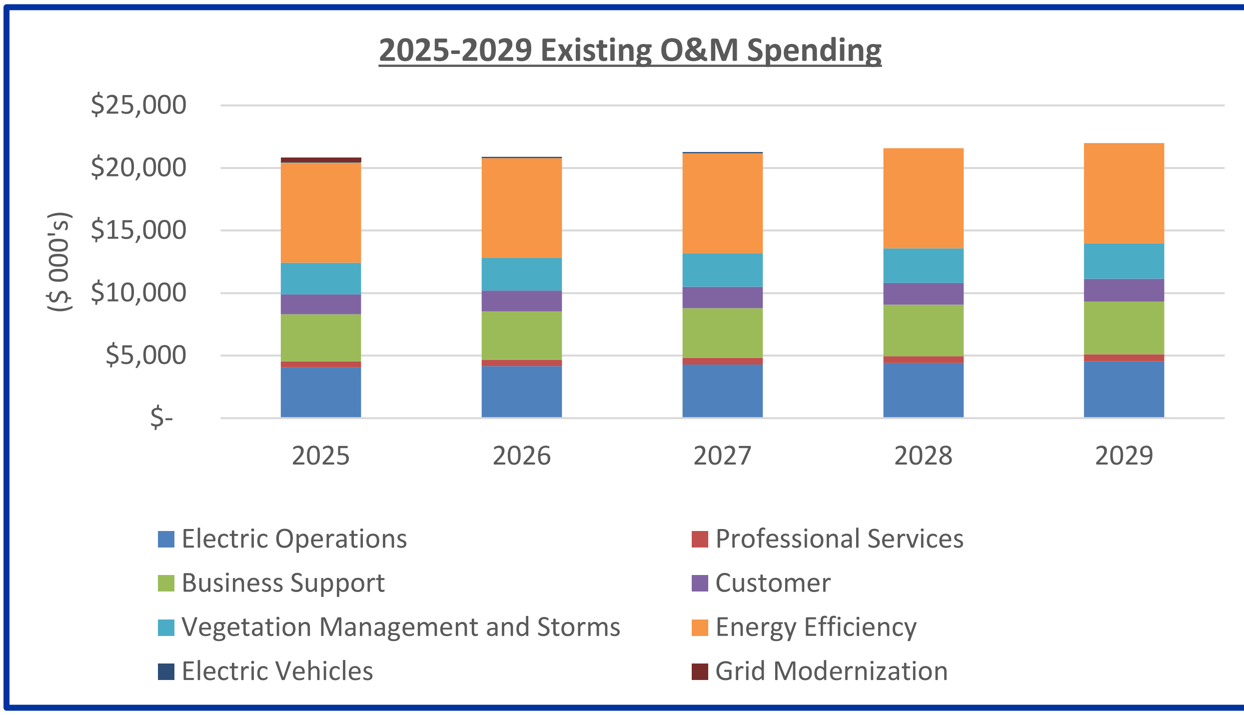

Figure 39 – 2025-2029 Existing O&M Spending

Category	2025	2026	2027	2028	2029
Electric Operations	$ 4,045	$ 4,166	$ 4,291	$ 4,420	$ 4,552
Professional Services	$ 499	$ 514	$ 529	$ 545	$ 561
Business Support	$ 3,751	$ 3,863	$ 3,979	$ 4,098	$ 4,221
Customer	$ 1,602	$ 1,651	$ 1,700	$ 1,751	$ 1,804
Vegetation Management and Storms	$ 2,529	$ 2,605	$ 2,683	$ 2,763	$ 2,846
Energy Efficiency	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000
Electric Vehicles	$ 92	$ 92	$ 92	$ -	$ -
Grid Modernization	$ 329	$ -	$ -	$ -	$ -
Total	$ 20,846	$ 20,890	$ 21,274	$ 21,578	$ 21,985

Table 55 – 2025-2029 Existing O&M Spending ($ 000's)

The chart and table below identify the capital spending by category for the 2025-2029 investments that are proposed or incremental ESMP investments.

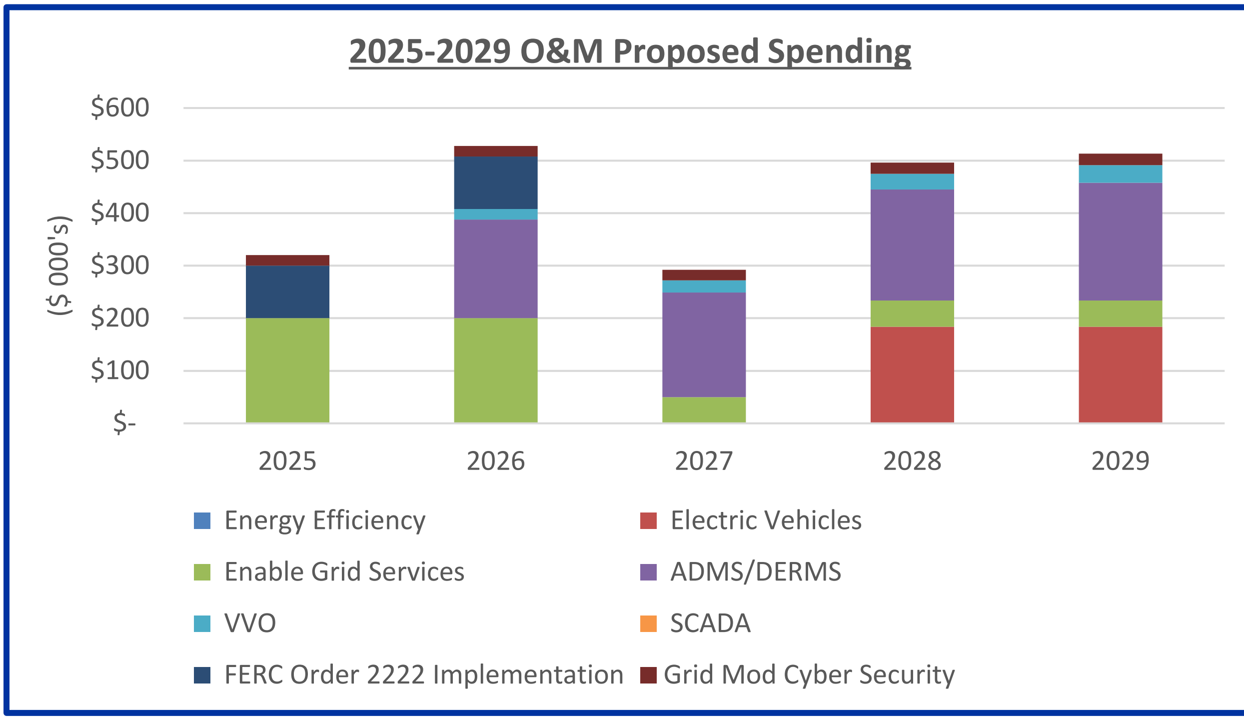

Figure 40 – 2025-2029 Proposed O&M Spending

Category	2025	2026	2027	2028	2029
Energy Efficiency	$ -	$ -	$ -	$ -	$ -
Electric Vehicles	$ -	$ -	$ -	$ 184	$ 184
Enable Grid Services	$ 200	$ 200	$ 50	$ 50	$ 50
ADMS/DERMS	$ -	$ 188	$ 199	$ 211	$ 224
VVO	$ -	$ 20	$ 23	$ 30	$ 33
SCADA	$ -	$ -	$ -	$ -	$ -
FERC Order 2222 Implementation	$ 50	$ 50	$ 50	$ 50	50
Grid Mod Cyber Security	$ 20	$ 20	$ 20	$ 21	$ 22
ESMP Proposed Spending	$ 75	$ 75	$ 75	$ 75	$ 75
Total	$ 345	$ 553	$ 417	$ 621	$ 638

Table 56 – 2025-2029 Proposed O&M Spending ($ 000's)

The chart and table below identify the existing and proposed O&M spending for the 2025-2029 investments.

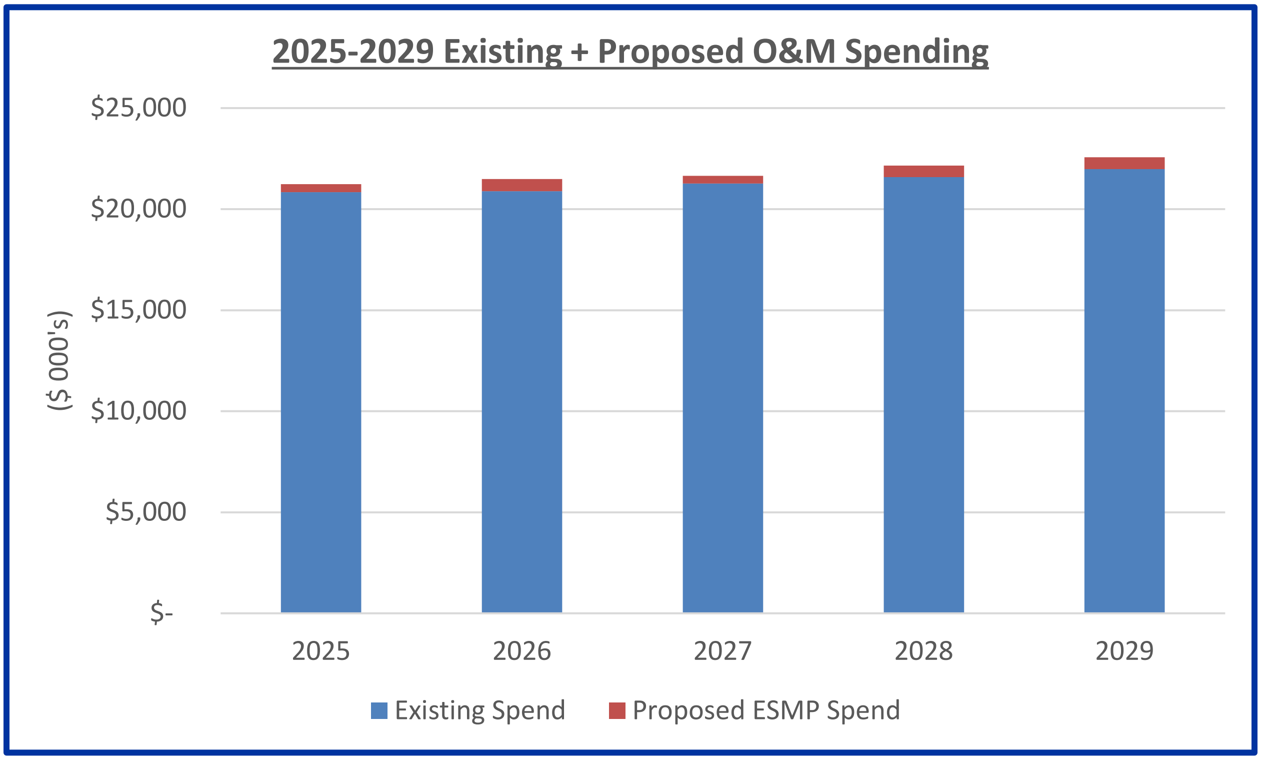

Figure 41 – 2025-2029 Existing + Proposed O&M Spending

Category	2025	2026	2027	2028	2029
Existing Spend	$ 20,846	$ 20,890	$ 21,274	$ 21,578	$ 21,985
Proposed ESMP Spend	$ 395	$ 603	$ 367	$ 571	$ 588
Total	$ 21,241	$ 21,493	$ 21,641	$ 22,149	$ 22,573

Table 57 – 2025-2029 Summary Existing/Approved + Incremental ESMP O&M Spending

The operating expense budget has been categorized as follows:[28]

Existing Operating Expense

- Electric Operations – Electric operations covers the operations and maintenance of the electric system including by not limited to: distribution maintenance, substation maintenance, street light maintenance, underground maintenance, metering, field services as well as the field and local supervisory labor associated with these activities.

[28] Note the operating expense budget shown does not include the power purchase expense items.

- Professional Services – These are external services the Company hires out when additional resources are needed or specialized skills are needed.
- Business Support – Business support includes the functions related to supporting the business, such as, billing, postage, insurance, customer outreach, banking fees, software fees, regulatory assessments, telecom and service company allocations.
- Customer – Customer includes functions such as, costs associated with credit and collections and the provisions for customer bad debt.
- Vegetation Management and Storms – Vegetation Management activities include hycle pruning hazard trees and storm resiliency program maintenance activities.

Previously Approved Operating Expense

- Energy Efficiency – This category represents the program administration fees associated with the Company's EE program through Mass Save. The amount shown in the table assumes a consistent level of funding based upon the most recent 3-year plan. The Company is not proposing new or additional energy efficiency funding through the ESMP program.
- Electric Vehicles – Electric vehicle expense includes the Department approved customer refund and reimbursements for residential EV charging facilities. This spending was previously authorized in D.P.U. 21-92.
- Grid Modernization – Grid Modernization expense includes the Department approved grid modernization expenses. This spending was previously authorized as part of Dockets D.P.U. 15-121 and D.P.U. 21-82.

Proposed new Operating Expense

- Electric Vehicles – Electric vehicle expense includes proposed new or incremental expenses not previously authorized by the Department in Docket DPU 21-92 for the extension of customer refund and reimbursements for residential EV charging facilities.
- Grid Modernization – Grid Modernization expense includes proposed new or incremental grid modernization expenses not previously approved by the Department in D.P.U. 15-121 and D.P.U. 21-82 for the extension of existing as well as proposed grid modernization projects.
- ESMP Program Administration – The administration of this plan will require funding to be successful. This funding would be used for stakeholder outreach and any measurement and verification efforts (similar to grid modernization).

In an effort to provide a consistent view and categorization of the proposed O&M spending, the Company has provided the table below which categorizes the investments, provides a summary of each category, describes where the cost of the investment categories are recovered and provides the 2025-2029 O&M spending.

Category	Summary	Recovery	2025-2029 O&M Spending
Electric Operations	Programs to support safe and reliable service, including equipment repair, new customer connections, peak load growth, maintaining reliability in line with Service Quality metrics	Base rate case	$21.5M
Storm	Estimates of storm costs for response during critical events	Base rate case	$13.4M
Business Support	Costs for support of operations including Finance, Human Resources, Legal, Communications	Base rate case	$22.5M
Customer	Costs to support customer experience including communications, billing, and other programs	Base rate case	$8.5M
EV Program	Deployment of EV make-ready and charging infrastructure	EV Tracker (through 2026/2027)	$0.3M (2025-2027)
Energy Efficiency, Electrification, and Demand Response	Assumes continuation of the Company's most recent three-year EE plan (2022-2024) to administer various EE, DR, and EHP incentives programs as part of Mass Save.	Energy Efficiency docket	$40M
Grid Mod	Technologies to increase grid visibility and control, integrate DER and support peak demand reduction	Grid Mod Factor (through 2025) Incremental ESMP (2026-2029)	$0.4M (2025) $1.0M (2026-2029)
Solar	Utility-owned solar and energy storage in applications that support community climate resilience	Individual projects filed with DPU	N/A
AMI	Deployment of meters, supporting technology, customer data sharing, outreach to customers	Grid Mod Factor (through 2025)	N/A
Network Investments	Operating costs associated with network investments.	Incremental ESMP	N/A
Grid Technology	Platform technologies, customer compensation fund demonstration and studies to advance VVP programs for DER as grid assets, customer portals	INCREMENTAL ESMP	$0.8M
Solar	Continuation of existing Solar/Storage community program	INCREMENTAL ESMP	N/A
Electric Vehicles	Continuation of existing EV make ready and charging infrastructure enablement programs	INCREMENTAL ESMP (2028 – 2029)	$0.4M (2028-2029)
ESMP Program Administration	Program administration of incremental ESMP projects	INCREMENTAL ESMP	$0.4M

Table 58 – 2025-2029 Existing/Approved + Incremental ESMP O&M Spending

7.1.1 Alternatives to proposed investments – Estimates of Impact of Investment Plan Alternatives

As described in the preceding sections, the Company has developed this Plan in response to the forecasted increase in customer loads, DER interconnections, electric vehicles, electrification of residential heating and other projects. The Company's detailed planning process identifies system constraints and develops alternatives for those investments. This detailed process in conjunction with the Company's planning criteria, ensures the safe, reliable, resilient and affordable operation of the electric system while working towards helping the Commonwealth realize its GHG emission targets. The Company must complete the projects associated with capacity expansion in the next several years to ensure sufficient capacity to serve new loads.

The Company is proposing to increase the capacity of Lunenburg Substation and the addition of a new South Lunenburg Substation as part of the Plan. These projects will increase the reliability of the system though providing additional capacity to serve the load as well as provide the opportunity for circuit modifications to reduce the overall size and customer exposure due to the reduced customer counts. The project will increase the hosting capacity of the overall area as it will reduce the loading on the 08 and 09 Lines as well as Flagg Pond Substation. This ensures the capacity will be available to support electrification of transportation and building sectors as well as increase the hosting capacity for the integration of new DERs such as PV, ESS, wind or other.

According to the Company's Project Evaluation Procedure, projects of this scale/cost would typically necessitate the review of non-traditional alternatives if the constraint allowed for construction to start three- to five-years in the future. However, due to forecasted load additions, these projects require construction to begin prior to the three-year construction start threshold, and as such only traditional alternatives were considered as options to address the identified constraints. The Company is continually evaluating project needs and will continue to assess the viability of NWA solutions for suitable needs.

The Company is proposing to continue with grid modernization investments. When the Company filed its initial grid modernization plan in 2015, it proposed a comprehensive deployment of grid modernization technology across the service territory so all customers could benefit from these investments as opposed to those customers served from individual circuits.

The Company believes that DERs that are reliable and available to respond to electric system needs can be beneficial to the safe and reliable operation of the electric system. However, the Company is currently not able to compensate customers for this type of use. The Company along with the other EDCs, are proposing studies and a compensation fund to develop and enable a compensation system for DER providing grid services. Compensation mechanisms along with the tools and information required to integrate these DERs into the real-time operation of the electric system are important next steps in the evolution of the distribution system.

7.1.2 Alternative approaches to financing

The Company's proposed projects in this Plan fall into two different categories: 1) grid modernization; and 2) capacity expansion or network investments for load. The grid modernization projects are predominantly a continuation of the existing grid modernization projects currently being implemented by the Company. The capacity expansion or network investment projects are focused on increasing capacity for load, but these projects will also inherently increase the hosting capacity of the distribution system.

The Company has experienced a high level of penetration with respect to DERs (specifically rooftop solar) interconnections. However, the quantity and size of the DER interconnections have not driven the need for group studies or the implementation of CIP project funding.

In the future, should the Company find the need to conduct a group study that results in significant capital investment, the Company proposes to apply the CIP approach approved by the Department in in D.P.U. 20-75-B. Any new CIP proposal would be evaluated on a case-by-case basis and submitted to the Department for review and approval.

Federal and state funding opportunities may also become available as an alternative means to fund investment. The US Department of Energy has made funding available through the Infrastructure Investment and Jobs Act. This is also more commonly known as the Bipartisan Infrastructure Law. The Company was unsuccessful in its full application submitted for the AMI project. As described above, the Company was successful in a grant award from the MassCEC for our Townsend Substation Battery project. The Company will continue to review federal and state funding opportunities as an alternative funding source for project.

7.1.3 Customer benefits

Customer benefits associated with the major investments in the Company's five-year plan are aligned with the 2022 Climate Act at 92B (B), which states that for all proposed investments and alternative approaches, each EDC shall identify customer benefits associated with the investments and alternatives including, but not limited to, safety, grid reliability and resiliency, facilitation of the electrification of buildings and transportation, integration of DERs, avoided renewable energy curtailment, reduced GHG emissions and air pollutants, avoided land use impacts, and minimization or mitigation of impacts on the ratepayers of the Commonwealth.

The figure below illustrates the definitions of these eight benefit categories as the Company interprets how they align with the Commonwealth's clean energy and climate goals. Overall, the Company has identified customer benefits for the ESMP as a component of the net benefits analysis, showing how the ESMP delivers substantial net benefits to customers. The methodology and results of the net benefits analysis are summarized in Section 7.1.4.

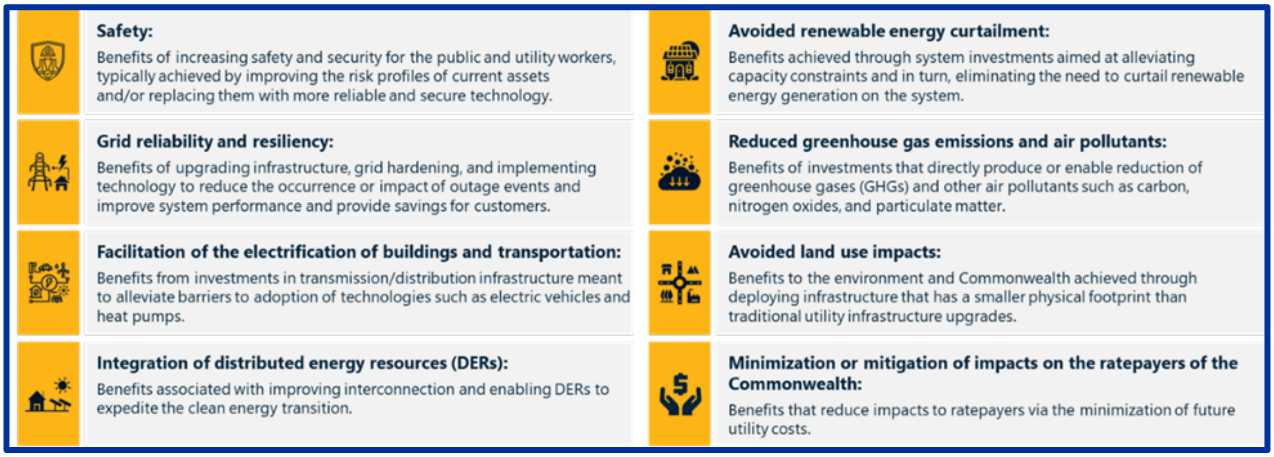

Figure 42 – Benefits span eight primary categories outlined in the 2022 Climate Act

The 5-year Plan is designed to address each of the customer benefit categories listed above:

- <u>Safety</u> – Safety is the highest priority of the Company. Public safety and employee safety is paramount to the investment plan provided by the Company. Each and every project and program is designed, constructed and maintained to improve the overall safety of the system.
- <u>Transparency</u> - The goal of the ESMP is to implement a transparent planning process ensuring the benefits of the plan are distributed in an equitable manner with special attention to providing benefits to Environmental Justice communities and historically disadvantaged communities. The ESMPs provide an important first step in enhancing the transparency of electricity network investment plans and the rationale for them among the Commonwealth's utilities. This Plan supports a transparent planning process to enable all uses of the electric system while maintaining flexibility to alter the plan to address future challenges that have not yet been identified.
- <u>Grid Reliability and Resiliency</u> - Electrification will increase the need for improved reliability and resiliency of the system. Climate change may have an impact with more frequent and more severe storms. The Company's vegetation management program (including its cycle pruning and Storm Resiliency Program) has a large impact on the reliability performance of the Company. The Company's Plan includes targeted reliability

and resiliency projects designed and justified specifically to address reliability and resiliency concerns across the system. In addition, the design of the substation investments includes more circuit positions to reduce the overall size of circuits thus reducing the impact of outages on those circuits as well as additional capacity which will provide the opportunity to restore circuits from alternate sources following an outage.

- Facilitation of Electrification of Buildings and Transportation – As described in sections 5 and 8, the Company's load forecast and demand assessment support the Commonwealth's clean energy goals. As a result of the load forecast and demand assessment, the Plan includes projects to increase the capacity of the system to accommodate electrification of buildings and transportation. The Company updates its load forecast and demand assessment annually to incorporate the latest information on technology adoption rates, electrification rates, building code changes and DER adoption rates which may have an impact on the forecasts.
- Integration of Distributed Energy Resources (DER) – The Company actively manages its interconnection process to effectively and efficiently interconnect DERs onto the electric system. Approximately 12% of the Unitil electric customers have DG in service or approved to install at their residence or facility and that is expected to grow. As described in sections 5 and 8, the Company's load forecast and demand assessment support the Commonwealth's clean energy goals. The Company has proposed: a) network projects which will increase the hosting capacity of the system; b) a joint study and program to compensate DERs providing grid services; c) a technology platform to support FERC Order 2222 access for DERs; and d) implementation of a DERMs platform. All of these projects are designed to improve the integration of DERs with the system.
- Avoided Renewable Energy Curtailment – The projects designed to integrate DERs also help to avoid renewable energy curtailment. Interconnection studies and impact studies are used during the interconnection agreement process to ensure that the facilities can connect safely and reliably to the electric system. The investments described above will enable the system to not only interconnect, but to benefit from these interconnections.
- Reduced Greenhouse Gas Emissions and Air Pollutants – The Company also has made a commitment to reduce direct company emissions by 2030 and reach net zero direct company emissions by 2050. This Plan is designed to support the Commonwealth's clean energy and decarbonization goals. The electric system is being designed to support building and transportation electrification. Interconnection of renewable energy sources and other DERs will continue to reduce the reliance on other sources of power. The Company proposes the continuation of its VVO program that is designed to reduce energy consumption, peak demand and reduce line losses. The Company provides energy efficiency programs to residential, municipal, commercial, and industrial customers

throughout the service territory which continue to be the most economical way to avoid greenhouse gas emissions and aid climate efforts.

- Avoided Land Use Impacts – The Company works diligently with the design of their projects to minimize the impact on the land, including environmentally sensitive areas. In addition, the Company's vegetation management program uses techniques to maintain and in most cases improve the habitats along our rights-of-way.
- Mitigation of Impacts on the Ratepayers of the Commonwealth – Affordability is always a concern. This plan, as well as our business as usual spending, is designed to provide safe and reliable service to our customers at affordable rates. This begins with a detailed planning process which is used to identify when investments are required. Alternatives are identified to ensure the Company is implementing the most cost effective alternative to alleviate loading or condition based violations. Our Project Evaluation Procedure is used to identify non-traditional alternatives to compare against the traditional alternatives. The Company continues to invest in our EE programs which have the impact of reducing loads and deferring capacity investments. The Company proposes to continue to invest in VVO which provides an immediate benefit to customer by reducing their electric consumption without taking any other action. The Company continues to offer rate plans and assistance to low and moderate income customers. The Company supports further discussion between the Department, stakeholders and EDCs on alternative rate mechanisms designed to ensure that costs and benefits are distributed equitably.

The Company's Plan meets the objectives of the legislation and is in line with the Commonwealth's pathway to a clean energy future.

The Company is proposing additional funding above its base funding for reliability and resiliency to support targeted undergrounding or targeted spacer cable in areas where vegetation management activities may not be allowed. SCADA Automation projects increase the monitoring and control of the system further out on the distribution system and allow for automated switching and restoration during outage events. The Company's ADMS and DERMS proposal will enable the Company to operate the system in a safe and reliable manner and optimize system demand and generation resources.

The Company's system forecast and demand assessment allows for the interconnection of 254 MW of solar, approximately 21,000 heat pumps and over 50,000 vehicles by 2050. The investments proposed in this Plan and future plans will serve as the foundation to serve all of these different load and resources. The Company has reviewed the forecast of DER interconnections and believes that the hosting capacity of the substation transformers and sub-transmission system will be sufficient if the upgrades identified in Section 6 are completed.

Technology	State-wide Climate Target	Unitil Proportional Share of Target	Unitil Forecast
Solar PV (MW)	27,000	254	254
Energy Storage (MW)	3,000	54	60
Electric Vehicles	5,400,000	50,292	50,841
Electric Heat Pumps	2,000,000	20,622	21,201

Table 59 – Unitil Alignment with State Goals

Unitil, through its EE and DERMs programs, is promoting and enabling energy storage and electrification technologies. The Company is also proposing studies and a compensation fund to enable DERs as grid services in coordination with the other EDCs, as well as proposing tools and software in preparation for the final FERC 2222 Oder that allows the aggregation of DERs.

In Section 10 the Company describes its approach to assessing the impact of climate change on our system. The next step for the Company is to develop alternatives to mitigate these risks.

This entire Plan is developed with affordability in mind. The Company's VVO program, when implemented, is designed to reduce customer loads by 2% without the customer taking any action. The financial savings flow directly to the customer. The reliability and resiliency programs will reduce the impact and costs of outages on our customers. Our EE programs provide incentives to promote electrification and efficiency measures

The table below summarizes the benefits associated with each investment project.

Project	Benefits
Enable DERs as Grid Services	• Compensation fund and mechanism to promote DERs as grid services • Integration of DERs • Avoided Renewable Energy Curtailment • Connect up to 10 DERs greater than 500kW • 5MW to 10MW demand reduction across the system • Assuming five, 4-hour events, savings of 100 MW-Hr to 500 MW-Hr of energy savings. • Reduced GHG and Air Pollutants • Benefits EJC and non-EJC communities
ADMS / DERMS	• Foundational investment

	• Platform for SCADA, OMS, VVO and DERMS • Real time system monitoring and control • Functionalities: real-time load flow and circuit analysis, demand response, outage restoration, direct load control and network configuration. • Improved reliability and resiliency • Integration of DERs • Avoided Renewable Energy Curtailment • Reduced GHG and Air Pollutants • Benefits EJC and non-EJC communities
VVO	• Estimated 2% reduction in energy and demand • Approximately 2.5MVA in annual Peak Demand Reduction by 2029 • Approximately 7,700,000 kWh in annual energy reduction by 2029 • Approximately $3.2 million in annual bill savings by 2029 • Benefits accrue directly to customers without any customer interaction • Reduced GHG and Air Pollutants • Benefits EJC and non-EJC communities
Automation	• Foundational investment • Supports VVO implementation • Improved reliability and resiliency • Real time telemetry • Historical interval data • Remote monitoring and control of field equipment • Benefits EJC and non-EJC communities
FERC 2222 Implementation	• Supports the ability for aggregated DERs to enter into the wholesale market • Reduce capacity constraints • Integrate an increased amount of renewable energy resources • Reduced GHG and Air Pollutants • Support State energy policy • Integration of DERs • Avoided Renewable Energy Curtailment • Defer distribution investment • Enable customers to take control of their energy future • Benefits EJC and non-EJC communities
Lunenburg Substation	• Alleviates loading constraints on Lunenburg Substation transformer and associated equipment • Increases local load and DER hosting capacity by more than 15MW • Improved reliability and resiliency

	• Integration of DERs • Reduced GHG and Air Pollutants • Avoided Renewable Energy Curtailment • Facilitation of Electrification of Buildings and Transportation • Location does not negatively impact and EJ community
New South Lunenburg Substation	• Alleviates loading constraints on 08 and 09 Lines and Flagg Pond Substation • Increases system wide load and DER hosting capacity by more than 30MW • Improved reliability and resiliency • Reduced GHG and Air Pollutants • Avoided Renewable Energy Curtailment • Facilitation of Electrification of Buildings and Transportation • Location does not negatively impact and EJ community
EV Charging and Make Ready	• Implemented TOU rates to further promote EV adoptions • Incentivize residential customers to adopt EVs, additional incentives for low and moderate income customers • Additional 5 Level 2 and 1 DCFC chargers • Locations of charger can benefit EJ communities • Reduced GHG and Air Pollutants • 1,150 vehicles by 2029 and 2,291 vehicles by 2034
Targeted Reliability and Resiliency	• Targeted deployment of undergrounding and spacer cable in areas where traditional trimming is not allowed. • Improved reliability and resiliency • Reduced storm restoration costs related to less damage and fewer outside crews needed.
Energy Efficiency, Demand Response, and Heat Electrification	• Approximately 1.4 MW in demand response reduction • Approximately 1,242 metric tons of 2030 Avoided CO2e. • Over $23 million in total benefits • Contribute to the deferral of capital investments in some cases • Integration of DERs • Avoided Renewable Energy Curtailment • GHG emission reduction • Facilitation of Electrification of Buildings and Transportation • Benefits EJC and non-EJC communities

Table 60 – Customer Benefits and Business Case for Proposed Investments

In addition to the benefits identified above, the Company has identified the Workforce, Economic and Health benefits in Section 12 of this ESMP.

7.1.4 Net Benefits Analysis

The Company's proposed ESMP investments meet the requirements of the Climate Act and deliver benefits that will support long-term value for customers and enable the delivery of the public policy priorities of the Commonwealth. The Company completed a comprehensive net benefits assessment to capture the quantitative and qualitative benefits that customers will realize through delivery of its proposed ESMP investments. For a detailed summary of inputs, assumptions, and workpapers of the net benefits analysis, please refer to testimony Exhibit UN-Net Benefits-3, Net Benefits Analysis Report, and Exhibit UN-Net Benefits-4, Net Benefits Model Workpapers.

The Company forecasts the proposed ESMP investments will yield an estimated $1.2 million (present value) in quantified net benefits from investments completed in 2025 through 2029. In addition, the Company's proposed ESMP investments will help facilitate the achievement of the Commonwealth's climate goals by enabling significant levels of EVs and electric heat pump ("EHP") adoption, timely integration of DERs, modernizing the distribution system, and encouraging customers to shift energy consumption to avoid renewable energy curtailment, while maintaining safe and reliable service.

The net benefits analysis also considers qualitative benefits, which contribute value even if difficult to express in quantified, economic terms. Qualitative benefits from the ESMP investments include reduction of land requirements for traditional electric infrastructure, facilitation of the electrification of buildings and transportation, improved DER interconnection, minimization of the curtailment of renewable energy resources, increased customer and workforce safety, as well as benefits to and equity across EJ communities.

7.1.4.1 Methodology

The Company worked jointly with the other EDCs to develop a shared ESMP net benefits analysis methodology. The net benefits analysis produced both quantitative and qualitative benefits of the Company's proposed ESMP investments in accordance with the goals set by the Commonwealth.

Each EDC grouped their investments under common proposed ESMP investment categories with some differences in individual programs contained within investment categories, reflecting the differences among the EDCs' respective ESMPs. The figure below summarizes the common proposed ESMP investment categories that were agreed to by the EDCs, as well as the individual projects that the Company is proposing within each ESMP investment category. The Company's ESMP includes five categories of investments: Network Investments, Platform Investments, Customer Investments, EV Programs, and Resiliency.

ESMP Investment Categories	Common Description	Company Specific Investments
Network Investments	New substation and distribution line upgrades to support electrification load growth and DER interconnections, as well as investments to install and manage additional technology hardware to improve network operations and management.	Distribution Programs (VVO) South Lunenburg Substation Construction Lunenburg Substation Expansion
ESMP - CIP	Substation and line upgrades to enable DER interconnections with cost allocation	*N/A*
Platform Investments	Investments identified to leverage data, digitalization, and other platforms to optimize infrastructure and meet evolving customer needs	ADMS/DERMS Cybersecurity Automation
Customer Investments and Programs	New programs and demonstrations to advance VPPs and use of DER for grid services, and investments in new clean energy customer portals & enabling technologies.	FERC 2222 Enable Grid Services / NWA
EV Programs	Continuation of existing EV make ready and charging infrastructure enablement programs.	FGE EV Program
Resiliency	Undergrounding, reconductoring and other storm hardening infrastructure upgrades	Resiliency Investments (Spacer cable/ Undergrounding)
Solar	Programs to support adoption of solar and storage technologies in EJCs	*N/A*
ESMP Program Administration	Program administration of incremental ESMP projects	ESMP Program Administration

Table 61 – Common Incremental Investments Summary

The net benefits analysis evaluated the portfolio of the Company's newly proposed ESMP investments over the first five years of the ESMP (2025 through 2029), which are incremental to the Company's core investments.

The costs for the net benefits assessment include all expenditures (capital and operational) included in the Company's 2025 through 2029 ESMP as summarized in Section 7.1. For consistency with the duration of the benefits assessment, the costs also include estimates of the ongoing operational expenses to maintain the investments that would be in-service by 2029 over the lifetime of the asset or out to 2050, whichever occurs sooner.

The benefits assessment includes the benefits enabled from the Company's proposed investments that would be in-service by 2029. Benefits are modeled over the life of the asset or through 2050, whichever occurs sooner. For instance, a substation transformer that is put into service in 2029 will continue to support capacity on the network until 2050 and beyond, and thus will enable benefits resulting from the incremental adoption and usage of new clean energy technologies and resources over the duration of that timeline.

The net benefit estimates included in this section are based on a net benefits model calibrated to industry standard assumptions and any relevant inputs and assumptions cross-referenced with the other EDCs. Principles outlined in the National Standard Practice Manual ("NSPM") and DOE's Modern Distribution Grid documents state that net benefits should account for state regulatory and policy goals, account for all relevant costs and benefits (including hard-to-quantify), apply full life-cycle analysis, and assess investments as bundles and portfolios instead of separate measures. Accordingly, the EDCs developed a net benefits framework for the ESMP incremental investments using a "regulatory perspective",[29] as suggested in the NSPM, to evaluate the benefits categories as defined in the Commonwealth's 2022 Climate Act at 92B (B) for the ESMP, i.e., safety, grid reliability and resiliency, facilitation of the electrification of buildings and transportation, integration of distributed energy resources, avoided renewable energy curtailment, reduced greenhouse gas emissions and air pollutants, avoided land use impacts, and minimization or mitigation of impacts on the ratepayers of the Commonwealth. Furthermore, the net benefits analysis factors in broader economic and workforce benefits in addition to the benefits listed in Section 92B that result from the Company's ESMP using a RIMS-II analysis.

[29] https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf

The Company provided all data related to the costs of its proposed ESMP investments for use in the net benefits model. A common methodology for the investments common across EDCs was determined, and the EDCs then identified relevant input factors and assumptions that could be used to estimate the benefits enabled by the proposed ESMP investments.

Net benefits assessed in this analysis were aligned to the eight benefit categories outlined in the 2022 Climate Act. In addition, economic and EJC benefits of the investment proposals were captured in the net benefits analysis. The EDCs evaluated the potential categories of benefits enabled by the proposed ESMP investments and determined which categories of benefits could be quantified (monetized and non-monetized) and which could be described qualitatively.

Quantitative: Benefits were quantified when industry standard data and documented methods were available to do so, and further steps were taken to monetize those benefits when possible and appropriate (i.e., to avoid double counting). Quantitative benefits are calculated in the net benefits model. They are aggregated to form an overall result. Quantified benefits were calculated across the following categories:

- Reduced GHG emissions & air pollutants
- Facilitation of electrification of vehicles and building
- Grid reliability and resiliency
- Economic Benefits (via the RIMS-II model, described in Chapter 12)

Qualitative: These benefits are outcomes of the investments contained in the ESMP for which there is insufficient data to estimate quantitatively. These benefits were evaluated across the eight benefit categories described in the 2022 Climate Act and noted in the figure above. The net benefits analysis also captures the reduction of environmental burdens in pollution-affected areas, emphasizing historical inequities in EJCs.

The collective benefit contributions from the Company's proposed ESMP that were evaluated in the net benefits analysis – both quantitative and qualitative – are illustrated in the following section. It is important to recognize that while these attributions were made to support the creation of the net benefits analysis, it is the Company's proposed solution as a whole, and not the individual investment categories alone, that unlock these benefits to meeting the Commonwealth's climate goals. As such, individual investment categories should not be considered on their own – given certain investment interdependencies, alterations to one investment category may have cascading effects on the net benefits as a whole, as other investments within other categories may have a significantly altered benefit impact.

Legend - ■-Quantitative Benefit □-Qualitative Benefit

INVESTMENT CATEGORIES	Benefit Categories									
	Safety	Grid reliability and resiliency	Facilitation of the electrification of buildings and transportation	Integration of distributed energy resources	Avoided renewable energy curtailment	Reduced greenhouse gas emissions and air pollutants	Avoided land use impacts	Minimization or mitigation of impacts on ratepayers	EJC Impact	Economic Benefits
Customer Investments		□	□	□	□	□	□	□	□	■□
Platform Investments	□	■□		□	□	□	□		□	■□
Network Investments	□	■□	■□	□	□	■□		■□	□	■
Resiliency	□	■□					□	■□	□	■□
EV Programs			■□	□		■□		□	□	■□

Figure 43 – Benefits Attribution in the Net Benefits Assessment

7.1.4.2 Net Benefits Analysis Results

Quantitative Benefits

The net benefits analysis model shows the quantitative net benefits based on the investments associated with the first five years of the Company's proposed investments. The table below illustrates the estimated monetized benefits, nominal costs, and present value (PV) of the ESMP and is referred to as the principal net benefits analysis result.

BENEFITS & COSTS	**NOMINAL** *($M)*	**PV** *($M)*
BENEFITS *(Asset Life or through 2050)*:	**$139.4**	**$43.3**
Reduced greenhouse gas emissions & air pollutants	$115	$29.5
Grid reliability and resiliency	$2.5	$0.9
Minimization or mitigation on ratepayers of the Commonwealth	$10	$3.2
Economic benefits (RIMS-II Model)	$12	$9.7
COSTS:	**$53.3**	**$42.1**
Capital (5-year ESMP)	$49.7	$39.8
O&M (5-year ESMP)	$2.5	$2.0
Total Ongoing O&M	$1.1	$0.3
Net Benefits:	**$74.1**	**$1.2**

Table 62 – Net Benefits Model Results for Monetized Customer Benefits

The present value of monetized benefits outweighs the costs for the Company's proposed ESMP investments. It is important to note that the Company's proposed investments enable additional benefits that cannot be monetized or quantified, so the monetized benefits do not fully capture the true net benefits resulting from the proposed ESMP. The full suite of net benefits, both quantitative and qualitative, provide a holistic view of net benefits relative to the costs of the proposed ESMP investment portfolio.

As shown in the table below, these monetized benefits are largely driven by the reduction in GHG emissions enabled by the investments, the monetized impacts of which are estimated based on the social cost of the GHG or air pollutant emissions. These ESMP investments collectively enable emissions reductions by delivering additional capacity to electrify transportation and buildings, as well as to connect distributed generation. The expected fuel consumption savings from transitioning to electrified transportation and electrified heating over the 50-year benefits period further offset the cost of the investments, which is another monetary benefit of the ESMP.

		QUANTITATIVE BENEFITS BY INVESTMENT ($ PV)				
Investment category	**Investment cost ($M)**	**Reduced GHG emissions & air pollutants ($M)**	**Grid reliability and resiliency ($M)**	**Minimization or mitigation of impacts on ratepayers of the Commonwealth ($M)**	**Total benefits ($M)**	**Total Including Economic Benefits ($M)**
Network Investments	$34.2	$27.5	$0.3	$3.2	$31	
Resiliency	$4	N/A	$0.3	$0.02	$0.3	
Platform investments	$1.9	N/A	$0.3	N/A	$0.3	
Customer Investments	$0.9	N/A	N/A	N/A	N/A	$9.7
EV Programs	$0.8	$2	N/A	N/A	$2	
ESMP Program Administration	$0.3	N/A	N/A	N/A	N/A	
Total ($ PV)	**$42.1**	**$29.5**	**$0.9**	**$3.2**	**$33.6**	**$43.3**

Table 63 – Quantified Benefits by Investment Category

As shown in the figure below, the net benefits associated with these investments yield net positive results by 2041. Most costs occur in the five-year investment period, including capital costs for the five-year ESMP (2025 through 2029) and relatively small amounts of the ongoing O&M costs to maintain the investments that would be in-service by 2029 over the lifetime of the asset or out to 2050, whichever occurs sooner. Benefits are assessed from the in-service date in 2029 through 2050 and will increase over time as more clean energy devices (EV, EHP, solar) connect to the network, leveraging the capacity enabled by these investments.

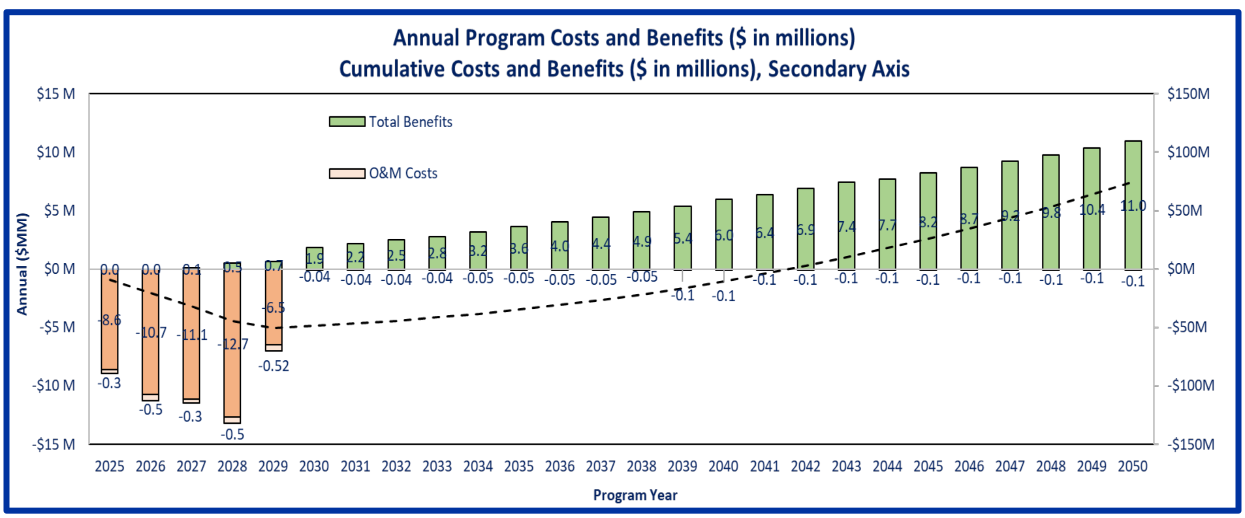

Figure 44 – Annual Program Costs and Benefits (2025 to 2050)

The net benefits analysis factors in the non-monetized benefits that result from the Company's proposed ESMP investments, which feed into the quantified, monetized result. These non-monetized benefits show quantitatively how the proposed ESMP investments in the first five years of the ESMP enable the Commonwealth's 2050 climate goals, support the customers of the

Commonwealth, and increase economic development.

Quantified Outcomes Driving Monetized Net Benefits	TOTAL
Total MT CO_2 Reduced	404K MT
Total MT NOx Reduced	80 MT
Total MT PM 2.5 Reduced	2 MT
Total Electric Vehicles Enabled	4,748 EVs
Total Heat Pumps Enabled	2,550 EHPs
Total Distributed Generation Enabled	30 MW

Table 64 – ESMP 5-Year Total Quantified Outcomes Diving Monetized Benefits

In addition to the net benefits assessment, the EDCs have also evaluated the economic benefits resulting from the Company's proposed ESMP. As part of the net benefits analysis, the Company performed a workforce and economic analysis, using the RIMS-II model. The results of the workforce and economic analysis, including direct and indirect jobs impact and economic impact (via the RIMS-II model), are discussed in Section 12.4 of the ESMP.

Qualitative Benefits

Qualitative benefits contribute value even if difficult to express in quantified or monetized terms. These benefits represent additional key reasons for implementing the portfolio of ESMP investments and related programs when considered in aggregate. The qualitative benefits and their alignment to the benefits outlined in the 2022 Climate Act are detailed in the table below. A key qualitative characteristic of this ESMP is the integrated nature of the package of investment proposals. This package of investments will collectively support the Company's ability and capacity to support the Commonwealth's emissions targets.

Category	Qualitative Benefit Description
Safety	• **Investment alignment with the Company's Guiding Principles of Safety and established equipment standards and work methods**, through assurances that professional safety protocols employed support the Company's regulatory and operational goals, its legal and customer obligations and its drive toward world class performance. • **Increased worker safety** via proposed investments that improve reliability which reduce time spent near electrical hazards, particularly during dangerous conditions (i.e., storm response). • **Improved protection of software systems and physical assets** from security threats and malware, enabling stable and secure operations.
Grid Reliability and Resiliency	• **Keeping our customers powered consistently and reliably** through grid-impacting events. While the impetus for the Company's substation and feeder projects is to address capacity deficiencies in supporting the Commonwealth's clean energy and climate targets, the network infrastructure investments will have secondary benefits in improving grid reliability and resiliency. For instance, the substation investments in locations identified as having a high risk of coastal flooding per the Company's Climate Vulnerability Assessment have incorporated flood mitigation considerations in the scope development. The Company's ESMP also includes technology investments such as early fault detection and active power restoration services, which would help improve reliability by proactively detecting faults and resiliency through integrating DER into the Company's outage restoration strategy.
Facilitation of the Electrification of Buildings & Transportation	• **Availability of adequate capacity and foundational enablement for clean energy** through expanded electric distribution infrastructure, to create adequate supply that meets the needs of customers transitioning to electric transportation and heating. • **Increased support for EV and electric heating adoption** via increased capacity and incentives from EV customer program extensions. • **Reducing the long queues at public and workspace chargers**, alleviating range anxiety and traffic through increased enablement of new, more accessible EV charger deployments.
Integration of Distributed Energy Resources	• **Remediating interconnection process pain points** which reduces the friction experienced by our customers to bring new clean energy assets online and electrify, such as through CIP proposals. • **Proactive capacity availability to make it easier for large spot loads to connect** in the future through substation and feeder investments. • **Improved customer connection experience** through increased transparency in the interconnection process, customer-facing portal

	enhancements, and DERMS investments to reduce the study time for new connections, as well as enabled flexible connections alternatives at scale.
Avoided Renewable Energy Curtailment	• **Increased grid flexibility** through platform investments and technologies that allow for a network which can leverage VPPs to provide grid services, support managed charging, power flow efficiency, and support initiatives like FERC 2222. These coordinated programs optimize grid operations and use of DERs to avoid distribution constraints, while avoiding renewable energy curtailment.
Reduced GHG emissions & air pollutants	• **Accelerating the transition to a Net Zero GHG economy, delivering on the CECP's GHG reduction goals.** The Company's collective investment proposal was engineered to support a higher integration of renewables and DERs, helping reduce dependence on fossil fuel generation, and decreasing the release of GHG emissions, which contribute to climate change. The company has developed quantitative estimates of the CO2 emissions reductions enabled from the ESMP, which are described in the quantitative section above. While the Company has included a quantitative assessment of GHG reduction benefits, there are qualitative benefits associated with delivering the state's climate goals that cannot be quantified. The analysis does not model methane (CH4) emissions quantitatively though acknowledges that CH4 is an even more potent GHG than CO2. The Company's investments may have downstream impacts on reduced CH4 as well. • **Reduction of other non-GHG, criteria air pollutants,** such as sulfur oxides (SOX), nitrogen oxides (NOX), and fine particulate matter (PM2.5), that have well documented impacts on respiratory and cardiac disease. While the Company used EPA to estimate the public health impacts associated with reducing these non-GHG emissions, the Company acknowledges that there could be other qualitative benefits associated criteria air pollutant emissions reductions, such as reduced smog.
Avoided Land Use Impacts	• **Reducing the requirement to build or expand traditional infrastructure** through enablement and maturity of non-wire alternatives (NWAs) that can help defer future network infrastructure deployment.

Minimization or mitigation of impacts on ratepayers	• **Creation of customer earning opportunities** through implementation of the necessary underlying metering and billing system changes so that customers can earn value by participating in future time-varying rates (TVR) and grid services programs. • **Minimizes future utility spend (and thereby reducing pass through to customers)** by optimizing grid planning, deployment, and operations, which reduces the need for infrastructure upgrades and break/fix. Additionally, the Company is maturing NWA and flexible connections capabilities in this ESMP, such that it can more confidently and precisely use NWAs in the future, which will provide alternatives to cost-effectively defer traditional infrastructure upgrades and their associated costs to customers.
Other ***(Benefits enabled outside those defined in the 2022 Climate Act)***	• **Make it easier for businesses to operate and thrive in the Commonwealth –** Investments in expanded capacity and supporting technologies will make the network "connection-ready" ensuring there is availability where it is needed to help expedite new customer connections, EV fleet adoption, electric heating conversions, and DER interconnection. The investments will also have secondary benefits on reliability and resilience. These attributes will help attract and retain businesses and associated economic activity within the Commonwealth. • **Progressing towards an additional 3,000 MW of capacity**. The Company's proposal for this ESMP period includes substantial costs associated with projects that will not be in-service until the 2030 through 2034 ESMP. As such, their associated benefits were not included in the net benefits analysis, but are tangible benefits that will be realized in a future ESMP period.

Table 65 – ESMP Qualitative Benefits Summary

7.1.4.3 The Company's Role in Driving Customer Benefits within EJ Communities ("EJCs")

While the proposed investments in the Company's ESMP were engineered to enable the timely realization of the 2022 Climate Act's long-term decarbonization targets among a plethora of additional benefits, the Company recognizes that several identified benefits are contingent on customer action – e.g., purchasing electric vehicles, electrifying space heating, or adopting other distributed energy resources. The Company also recognizes that many of our customers, especially those in identified EJCs, have historically faced high energy burdens, yet may not have adequate awareness of the available assistance programs, resulting in lower program enrollments.

A key goal of the Company's ESMP is to drive the investments and their associated benefits in a more equitable fashion going forward. The Company's net benefits analysis takes a holistic, territory-wide approach to estimating the net benefit of the total investment rather than quantifying outcomes on a community-by-community basis or by EJC. Benefits identified directly to EJC would require a number of presumptions on adoption rates or the modeling of specific customer behaviors that would also need to be both reasonable and defendable.

However, the proposed ESMP includes two (2) primary actions that will be driven by the Company, and where appropriate, in collaboration with the other EDCs, to break down historical barriers and facilitate benefit realization in a more equitable fashion. These include: (a) providing offerings and programs for EJCs and LMI customers that will allow them to more readily participate in the clean energy transition and lower their bills; and (b) establishing formal, accountable frameworks for stakeholder engagement and outreach such that customers are aware of and can take advantage of these programs, both described in more detail below:

a) **Providing Programs and Offerings for EJCs and LMI Customers.** As described in **Section 6** (**Section 6.1**) and in **Section 3** (**Section 3.4**), the Company outlines a number of specific EJC- and LMI-focused programs. These customer programs, such as its successful EE and EV programs, have benefited from the input of EJCs to inform program design that reflects community priorities. For example, engagement through the EE Equity Working Group has played a crucial role in establishing specific goals for equity and service for EJ populations. For EE and EV programs, more enhanced EJC incentives are offered for residential customers and more direct support of fleet electrification is a priority to reduce local air pollution.

b) **Supplementing with Intentional and Accountable Stakeholder Outreach**. As described in **Section 3** (**Sections 3.4 and 3.5**), engaging stakeholders in an equitable manner is critical for the development and execution of the Company's ESMP. This is supported by the establishment of two-way engagement channels, developing rigor in joint-collaboration (both across EDCs and with stakeholder groups), and providing tailored outreach to drive a community-centric focus that is both culturally competent and respectful to those communities' specific needs. This outreach can drive greater adoption of EJC- and LMI-specific programs, in turn allowing for the realization of the associated decarbonization benefits.

The Company takes seriously its commitments to driving equity in its ESMP with thoughtful and meaningful community benefit as a critical outcome requirement for the investment, spanning not just grid-benefitting operational improvements, but also in advancing energy democracy, workforce development, and community partnerships. These efforts will be iterated on and improved through future ESMPs.

7.2 INVESTMENT SUMMARY 10-YEAR CHART

The spending shown below considers existing capital spending programs (base budget), pre-authorized programs (i.e. EE, grid modernization and electric vehicles), and newly proposed spending (i.e. capacity, extended grid modernization, reliability and resiliency and customer facing programs) for a 10-year period from 2025-2034.

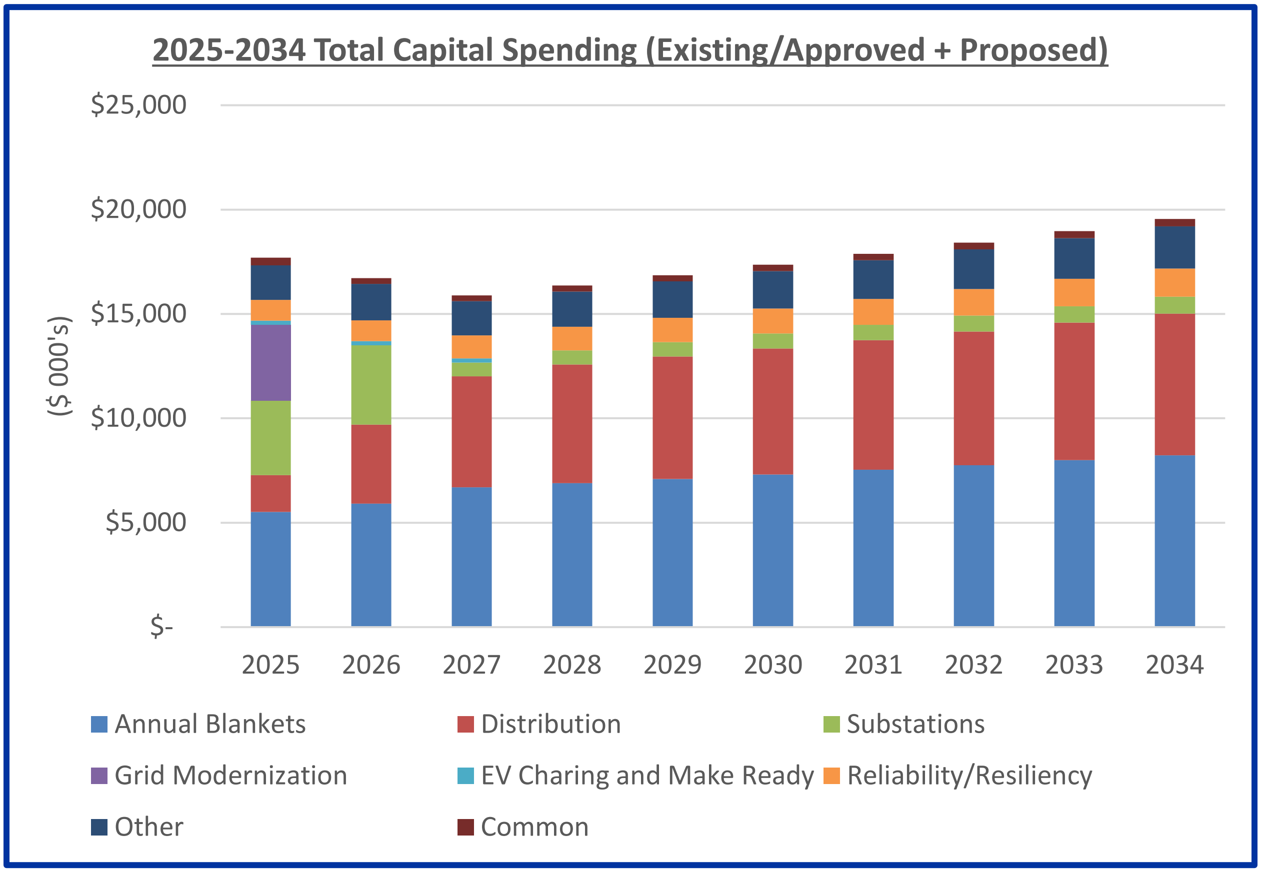

Figure 45 – 2025-2034 Capital Spending

The chart below displays the existing and proposed capital spending from 2025-2034.

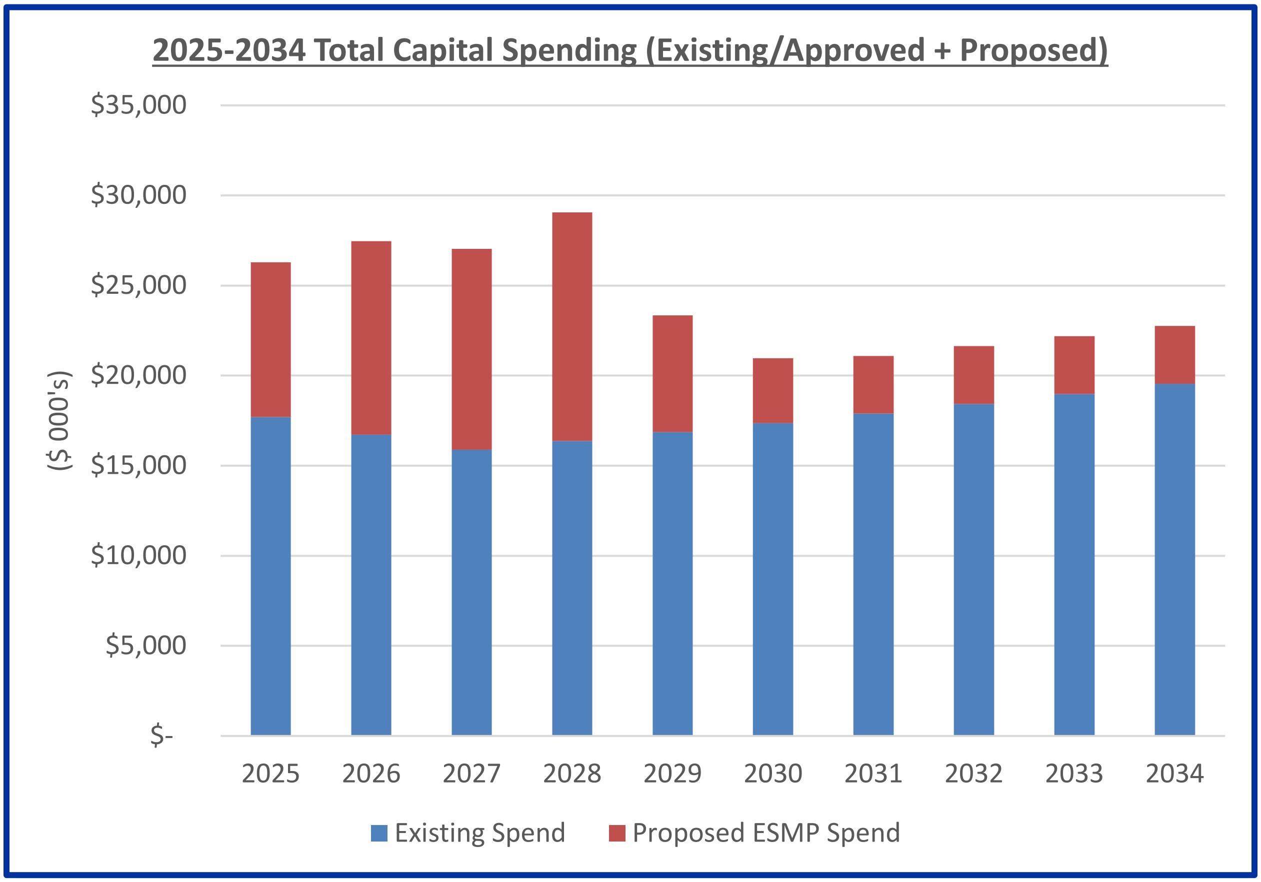

Figure 46 – 2025-2034 Capital Spending (Existing + Proposed)

7.3 EXECUTION RISKS – SITING, PERMITTING, SUPPLY CHAIN AND WORKFORCE CHALLENGES

The Company has taken a measured approach to this Plan. As a small utility, Unitil must focus on the needs of its customers. This plan consists of projects that are generally within the control of the Company from a design and construction standpoint. With that said, there are potential challenges to each of the projects proposed as part of this plan.

- Siting – Siting new electric infrastructure can be a challenging endeavor. The siting process takes time and patience. Siting electric infrastructure begins with identifying a constraint and study area. A transparent stakeholder engagement process which encourages feedback is critical to the success of the siting process. Identifying the possible range of solutions allows the stakeholders to understand the challenges and limitations of each solution. A detailed selection process that provides stakeholders with the opportunity to provide feedback will provide the greatest success for siting. Policy and structural changes to the Energy Facility Siting Board process may increase the efficiency and speed of the siting process.

- Permitting – Permitting electric infrastructure may be one of the most challenging steps to completing a project, and can sometimes take just as long as siting. The larger the project, the more people it may impact and the more challenging it is to obtain permits. Each permit has its own process and its own group of stakeholders. Any single permit can hold up a project from construction within the timeframe when it is needed. Some projects can require over a dozen permits depending on where the project is located and how many cities or towns the project impacts. Local, State and Federal permitting boards are stakeholders and should be included early in the process. A transparent stakeholder engagement process which encourages feedback is critical to the success of the permitting process. Policy and structural changes to the permitting processes may increase the efficiency and speed of the siting process.

- Supply Chain – Supply chain issues continue to challenge project in-service dates. Transformers, voltage regulators and meters continue to experience delivery times of 18-24 months. Smart devices used to make the grid more intelligent are experiencing challenges due to the lead-time of the computer chips needed to operate. Vendor relationships are critical to the success in receiving equipment within a reasonable timeframe. Project in-service dates must be set at a reasonable timeframe to order and receive materials.

- Workforce – A diverse set of skills are required to complete a project. Technical staff is required to design and specify the equipment; purchasing agents are needed to complete the competitive bidding process for equipment and contract services; stockroom staff are required for purchasing and receiving goods and materials; construction supervisors are required to supervise the field staff; various different skillsets are required for construction; accounting and finance staff is required to account for the project; and so on. The future grid will need three times the capacity of the existing system. Increasing the size of the workforce is critical to the decarbonization goals of the Commonwealth. Workforce is discussed more in Section 12.

8 2035 - 2050 POLICY DRIVERS: ELECTRIC DEMAND ASSESSMENT

The analysis informing the 2050 Roadmap Study highlights that electrification and the “All Options” pathway meet the 2050 emission reduction targets with the least cost while achieving deep decarbonization. The Company’s demand assessment forecast has been compared against the “All Options” pathway to ensure the Company’s Plan will contribute to the overall Commonwealth goal. To accomplish this, the Company scaled the Commonwealth’s goals and compared the scaled benchmark to the demand assessment. The assumptions in the Company’s demand assessment matched very closely for electric vehicles, residential heat pumps, solar and energy storage. The Company’s reviewed its demand assessment to ensure it is in line with the assumptions in the Commonwealth Energy Climate Plan for 2050.[30] The table below shows the comparison between the Commonwealth assumptions and the assumptions in the Company’s demand assessment.

[30] The Commonwealth Clean Energy and Climate Plan for 2050 assumes that 87% of the “small” (G41, G42, G43 and G51) commercial/industrial and 52% of the “large” (G52, G53 and Newark Special Contract) commercial/industrial gas load is electrified by 2050

Sector	Description	State Benchmark	Units	Scaled Benchmark	Units	Company Forecast	Units
Transportation Sector (Note 2)							
	Light-Duty EV	5,400,000		50,734	vehicles	52,841	vehicles
	Medium/Heavy Duty EV	353,000		3,316	vehicles		
Building Sector (Note 2)							
	Residential air source heat pumps	2,000,000		18,790	heat pumps	21,134	heat pumps
	Residential Ground source heat pumps	195,000		1,832	heat pumps		
	Residential EE Retrofits	1,300,000		12,214	homes	0	
	Commercial air source heat pumps	1,500,000,000		14,092,698	sq. ft.	Note 3	
	Commercial ground source heat pumps	140,000,000		1,315,319	sq. ft.	Note 3	
Power Sector (Note 2)							
	Offshore Wind	23.0	GW	216	MW		
	Onshore Wind	1.0	GW	9	MW		
	Solar	23.0	GW	216	MW	254	MW
	Storage	5.8	GW	54	MW	60	MW
Note 1	Massachusetts Census Data 2020 https://malegislature.gov/Redistricting/MassachusettsCensusData/CityTown						
Note 2	2050 Clean Energy and Climate Plan, Table 3-3 https://www.mass.gov/doc/2050-clean-energy-and-climate-plan/download						
Note 3	Company forecasts are based on peak gas usage of gas C&I customers						

Table 66 - Demand Assessment Assumption Comparison[31]

2035 to 2050 Peak Load Forecasts

Hourly interval load forecasts for both the winter and summer season for each of the years from 2035 to 2050 were developed by combining the hourly interval base, DER, ESS, EV and electrification forecasts above and incorporating VVO load reduction. The overall system peak load forecasts is the peak hourly load (winter or summer) of each year. The Company's 2035 to 2050 system peak load forecasts are included below.

The Company developed a sensitivity analysis for each of the forecasts (base, DER, ESS, EV and electrification) that were combined into the overall system peak forecasts. Based on current load growth and adoption and current equipment lead times the company selected an overall forecast with a lower growth/adoption rate in the early years of the forecasts with a higher growth/adoption rate in the later years. In the event the more aggressive growth/adoption rate

[31] Due to the Company's overall size, the probability for large scale wind (either on-shore or off-shore) to have an impact on the electric system is very low, as wind is more of a supply consideration for the Company. The Company has not included wind in its demand assessment.

is realized the need years for project could move 3-5 years sooner than currently forecasts and the less aggressive forecasts could defer project by one to two years.

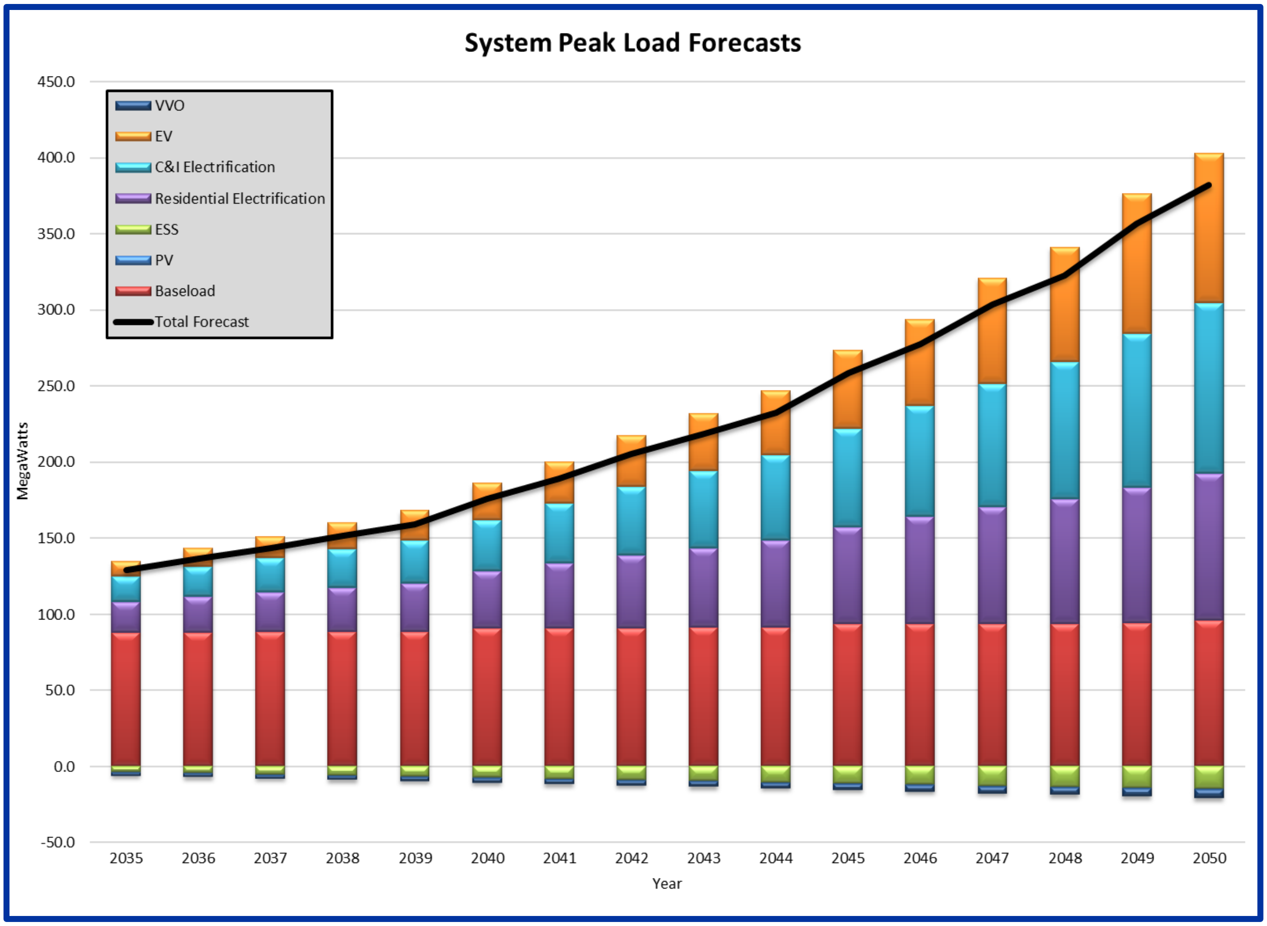

Figure 47 – 2035-2050 System Peak Load Forecast

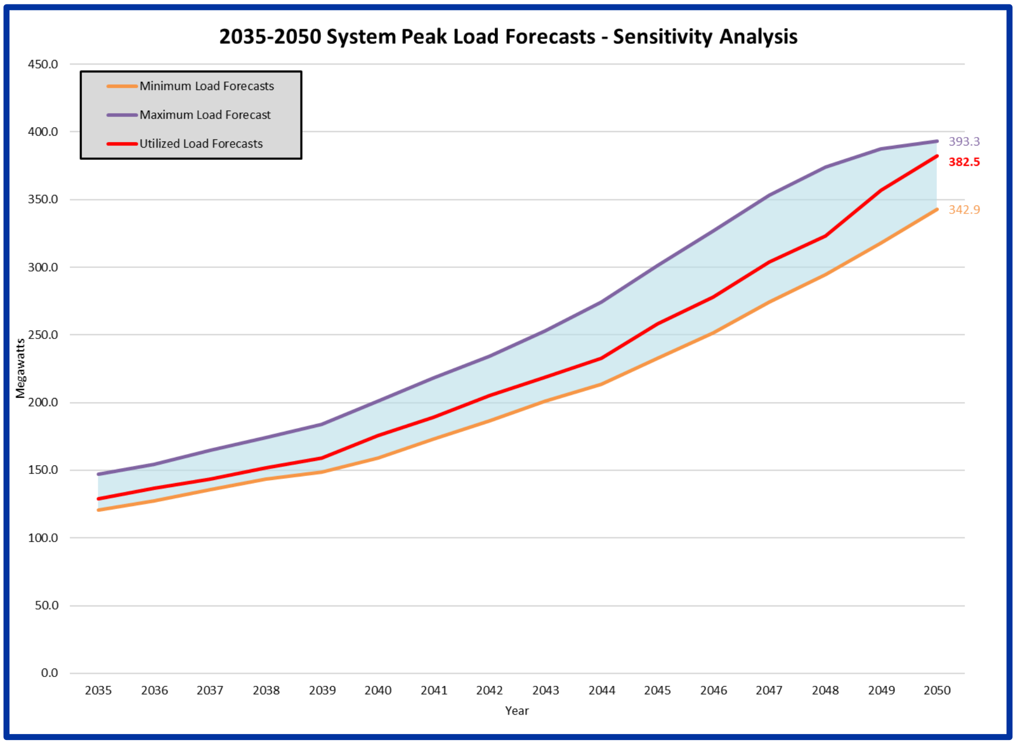

Figure 48 – 2035-2050 Load Forecasts – Sensitivity Analysis

	Total Peak Forecast (MW)	Contribution to Total (MW)							Season ESS	Hour
		Base	PV	ESS	Residential Electrification	C&I Electrification	Base	PV		
2035	128.9	88.2	0.0	-3.8	20.2	16.8	9.7	-2.3	Winter	7PM
2036	136.5	88.3	0.0	-4.5	23.3	19.6	12.0	-2.4	Winter	7PM
2037	143.4	88.5	0.0	-5.3	26.2	22.4	13.9	-2.5	Winter	7PM
2038	151.6	88.6	0.0	-6.0	29.2	25.3	17.2	-2.6	Winter	7PM
2039	158.9	88.7	0.0	-6.8	31.9	28.1	19.7	-2.7	Winter	7PM
2040	175.9	91.0	0.0	-7.5	37.4	33.7	24.2	-2.9	Winter	7PM
2041	189.1	91.1	0.0	-8.3	42.6	39.3	27.5	-3.1	Winter	7PM
2042	205.2	91.2	0.0	-9.0	47.7	44.9	33.7	-3.3	Winter	7PM
2043	218.9	91.3	0.0	-9.8	52.5	50.5	37.9	-3.5	Winter	7PM
2044	232.8	91.4	0.0	-10.5	57.3	56.1	42.1	-3.7	Winter	7PM
2045	258.4	93.7	0.0	-11.3	63.9	64.5	51.6	-4.0	Winter	7PM
2046	277.8	93.8	0.0	-12.0	70.5	73.0	56.8	-4.3	Winter	7PM
2047	303.9	94.0	0.0	-12.8	76.5	81.4	69.4	-4.6	Winter	7PM
2048	322.9	94.1	0.0	-13.5	82.0	89.8	75.4	-4.9	Winter	7PM
2049	357.1	94.2	0.0	-14.3	89.4	101.0	92.1	-5.4	Winter	7PM
2050	382.5	96.5	0.0	-15.0	96.0	112.2	98.5	-5.7	Winter	7PM

Table 67 – 2035-2050 System Peak Demand Assessment

It is important to note that the Company's 5- and 10-year forecasts and 2035-2050 demand assessment are tied together. The starting loads for the demand assessment forecast are taken directly from the 10-year load forecast. The assumptions used in the load forecast and the demand assessment are consistent with each other.

Net Powerflow

Net Powerflow forecasts for 2035-2050 are included in the table below. These were developed in a similar fashion to the 2025 to 2034 net powerflow forecasts.

Year	Net Powerflow (MW)
2035	-19
2036	-24
2037	-28
2038	-33
2039	-37
2040	-43
2041	-49
2042	-54
2043	-59
2044	-63
2045	-68
2046	-74
2047	-81
2048	-86
2049	-92
2050	-99

Table 68 – Ten Year Net Powerflow Forecast

There is a great deal of uncertainty when attempting to forecast loads to 2050. Changes in technology and the cost of technology can change drastically. Incentives and subsidies can have an effect of accelerating or slowing adoption rates. Technological advancement is a large unknown in this analysis. The Company expects this forecast will change over time and will continue to identify ways to increase the accuracy of the forecast.

8.1 REVIEW OF ASSUMPTIONS AND COMPARISONS ACROSS EDCS

The Massachusetts EDCs together have reviewed and compared overarching assumptions for future electric demand assessments across the Commonwealth. The overall forecasting strategies employed by each individual EDC share many similarities, especially with how they apply the impact of state- level clean energy scenarios.

All three EDCs develop DER scenarios from the different decarbonization pathways outlined in the CECP.

Category	National Grid	Eversource	Unitil
Heating Electrification	Utilizes "Phased" scenario, "Ful Electrification" scenario, and the "Hybrid" scenario	Utilizes "Phased" scenario, "Full Electrification" scenario "Hybrid" scenario, "High Electrification" scenario, and "All Options"	"All Options" pathway
Energy Efficiency	Assumes Energy efficiency offerings continue at a slower rate to reflect market saturation and competition for funding with heat pump offerings.	Does not forecast Energy efficiency savings	Assumes Energy efficiency offerings continue in line with historic trends
Demand Response	Existing Company DR programs continue with growth	Simulates scenarios with 5% DR and no DR	Not considered
Solar PV	"All Options" pathway outlined in the 2050 Roadmap	"All Options" pathway outlined in the 2050 Roadmap	"All Options" pathway outlined in the 2050 Roadmap
Storage	Between "All Options" and "Phased" Scenarios.	"High Electrification" Scenario	"All Options" pathway outlined in the 2050 Roadmap
Transpiration Electrification	Models load impacts of scenarios from adopting the California Advanced Clean Car (ACC II) Rule and Advanced Clean Truck Rule	EV baseline adoption rates from the 2050 MA CECP, with scenarios for moderate, high ideal managed charging participation	"All Options" pathway outlined in the 2050 Roadmap

Table 69 - Forecasting Assumptions Across Utilities

8.2 BUILDINGS: ELECTRIFICATION AND ENERGY EFFICIENCY ASSUMPTIONS AND FORECASTS

Building electrification will have the largest effect on electric peak load conditions of any other electrification technology. The energy needed to heat a given area is much greater than cooling the same area. When cooling an area, the temperature may need to be decreased by 10 degrees to make the area comfortable. However, in heating applications, temperature may need to be increased by 18 to 68 degrees,[32] as compared to the outdoor temperature to make the area comfortable.[33] Also in heating applications, the temperature drops much faster (depending on the efficiency of the building envelope) resulting in the heating system running more frequently to maintain temperature. In addition, as the ambient temperature decreases, the overall efficiency of the heat pump will have a tendency to decrease, resulting in increased electric loads to heat the same area.

Electrification of heating loads will have the effect of transitioning the system peaks from the summer (due to cooling loads) to the winter (due to electrified heating loads). In addition, those peaks are likely to occur in the morning hours when customers wake up and business open for the day. Cooling peak loads have typically overlapped with solar production during the middle of the day. However, heating peak loads will happen early enough in the morning that the contribution from solar production on the system will be minimal.

The forecasting of 2035 to 2050 electrification load was done similarly to how electrification was forecasted for 2025 to 2034, with lower coincident factors and 5 percent[34] adoption rates (percentage of total forecasted load incorporated per year).

8.2.1 Technology assumptions

The Company focuses this analysis on residential electrification (heating and appliances) and commercial electrification (electrification of gas loads).

Residential Electrification:

The Company considers two types of residential electrification in its load projections, appliance load and heating/air conditioning load. In order to develop load forecasts for each of these load types the Company made the following assumptions.

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[32] 18 degrees assumes an outdoor air temperature of 50 degrees and an internal setpoint of 68 degrees and 68 degrees refers to an outdoor temperature of 0 degrees with an internal setpoint of 68 degrees.

[33] MA 105 MCR 410.180 requires temperatures of at least 64 degrees Fahrenheit at night and 68 degrees Fahrenheit during the day from September 15 to May 31.

[34] 5 percent per year adoption rates were used to be in line with the Commonwealth Clean Energy Climate Plan for 2050.

- An average square footage of a residential dwelling in the service territory of 1,500 square feet.
- Heating/AC Sizing[35]
    - 20 btu/sq. ft. for air conditioning
    - 50 btu/ sq. ft. for heating
- Heating/AC Heat Pump SEER of 18[36] (13.68 btu/W)
- Heating/AC Ground Source Heat Pump 40% more efficient than Air Source Heat Pump
- Type
    - 10% Ground Source Heat Pump
    - 90% Air Source Heat Pump
- Current customer AC usage
    - 30% with central AC
    - 40% with window AC
    - 30% with no AC
- All natural gas customers have gas heat, ranges and dryers.
- Typical Electric Dryer Peak Load of 5kW[37]
  Typical Electric Range Peak Load of 6kW[38]

[35] Based upon International Energy Conservation Climate Zone Map
[36] Based upon manufacturer data for an "average" efficiency unit
[37] Based upon typical nameplate data and National Electric Code loads.
[38] Based upon typical nameplate data and National Electric Code loads.

Hour of Day	Appliance	Heat/AC	Hour of Day	Appliance	Heat/AC
0:00	5%	50%	12:00	25%	65%
1:00	5%	50%	13:00	25%	65%
2:00	5%	50%	14:00	10%	80%
3:00	5%	50%	15:00	10%	80%
4:00	5%	50%	16:00	25%	80%
5:00	10%	65%	17:00	25%	80%
6:00	15%	65%	18:00	25%	80%
7:00	25%	80%	19:00	25%	80%
8:00	25%	80%	20:00	10%	80%
9:00	10%	65%	21:00	10%	80%
10:00	10%	65%	22:00	10%	65%
11:00	10%	65%	23:00	5%	50%

Table 70 – Hourly Electrification Utilization

The assumptions above along with coincident assumptions, which decrease over time based on the amount of electrification were used to develop hourly residential electrification peak day forecasts. The hourly residential electrification forecasts are then added to the hourly base seasonal peak load forecasts.

Commercial/Industrial Electrification:
The Company utilized peak gas loads for all commercial/industrial gas customers as the basis for is commercial/industrial electrification load forecasts along with typical hourly electric profiles for the same customer types and the following assumptions to hourly commercial/industrial electrification load forecasts. These forecasts were then added to the hourly base seasonal peak load forecasts.

- Estimates Peak Hour Gas Usage[39]
    - "Small" Commercial/Industrial – 437 DTH
    - "Large" Commercial/Industrial – 61 DTH

[39] Based upon "average" Unitil customer

- 293 kW/DTH
- % of Customers to Electrify[40]
    - "Small" Commercial/Industrial – 87%
    - "Large" Commercial/Industrial – 52%

8.2.2 Adoption propensity assumptions

The Company has taken the following approach to adoption:

- Adoption (% of Total Forecasted Load Incorporated per Year)
    - 2025-2029 – 1%
    - 2030-2034 – 2%
- 80% of all residential customers will convert to electric heat by 2050[41]

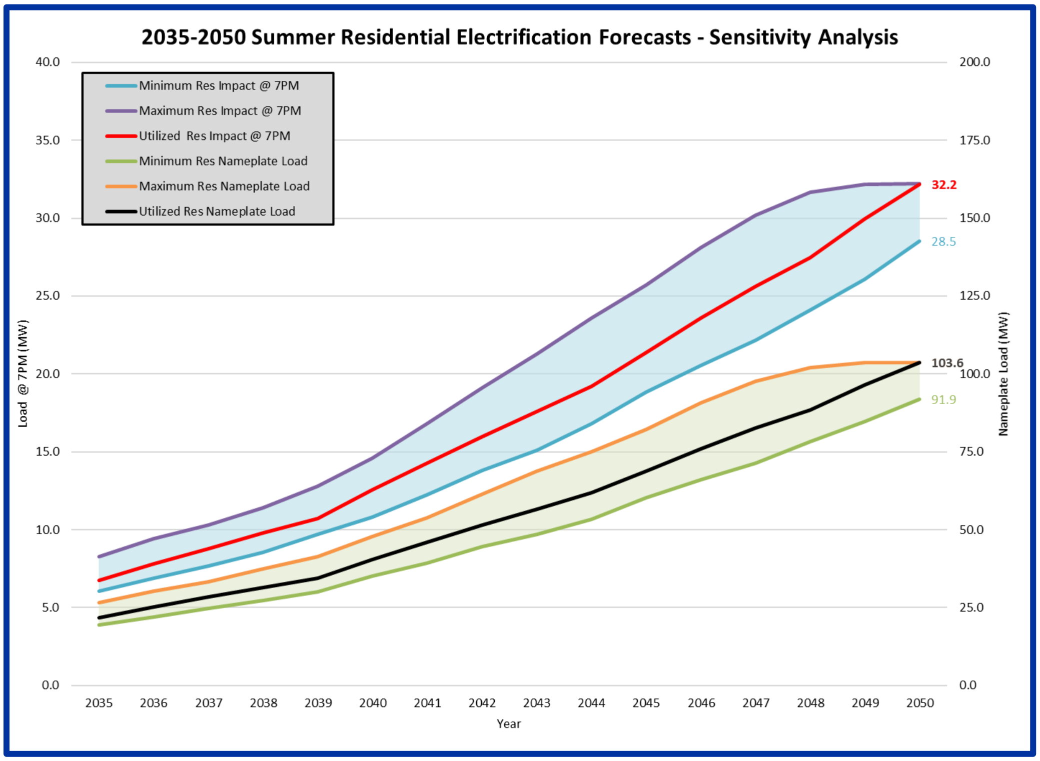

Figure 49 – 2035-2050 Summer Residential Electrification Forecasts – Sensitivity Analysis

[40] Based upon Commonwealth Clean Energy and Climate Plan for 2050, https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050

[41] Based upon Commonwealth Clean Energy and Climate Plan for 2050, https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050

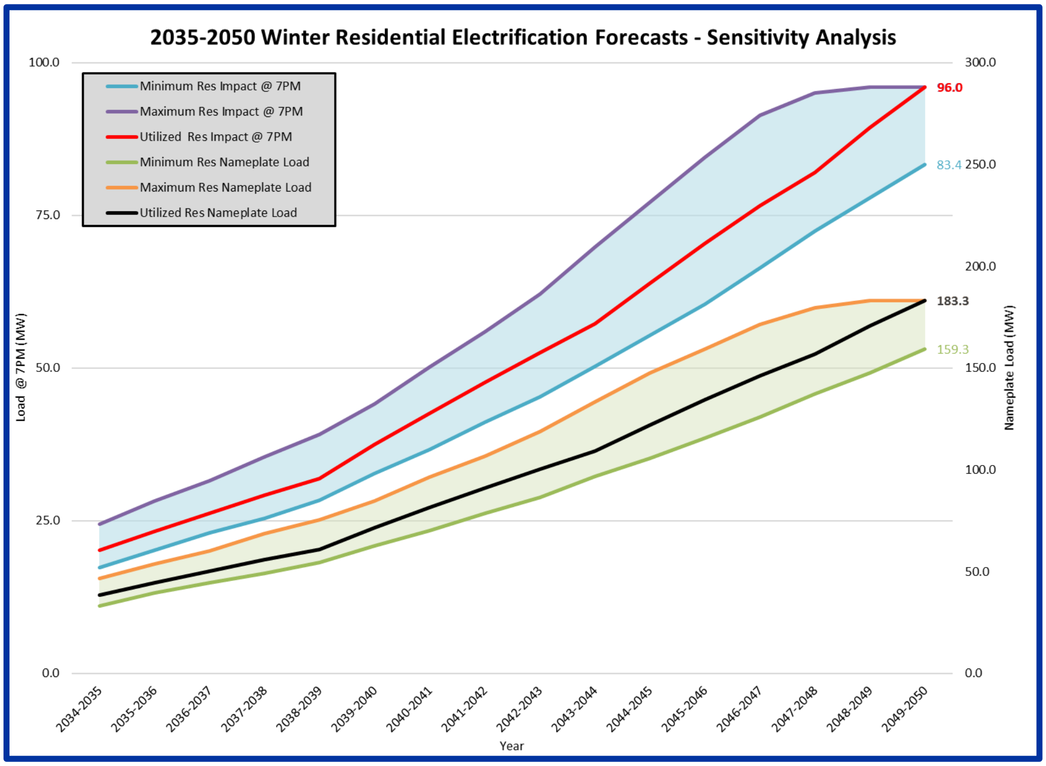

Figure 50 – 2035-2050 Winter Residential Electrification Forecasts – Sensitivity Analysis

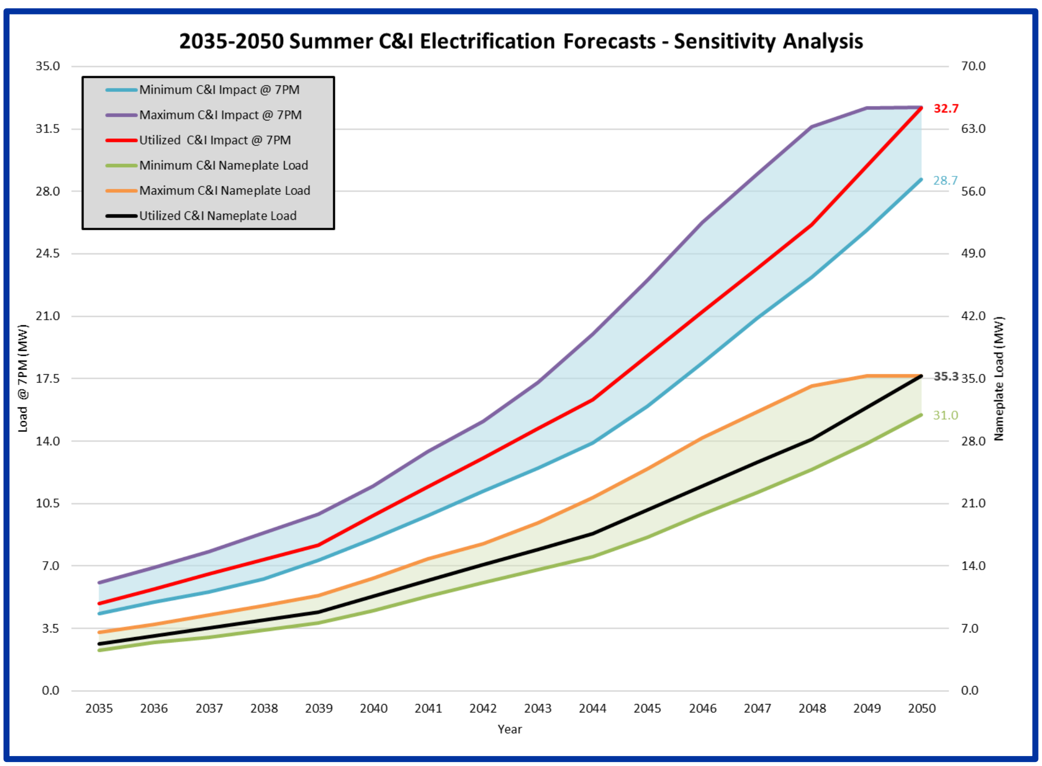

Figure 51 – 2035-2050 Summer C&I Electrification Forecasts – Sensitivity Analysis

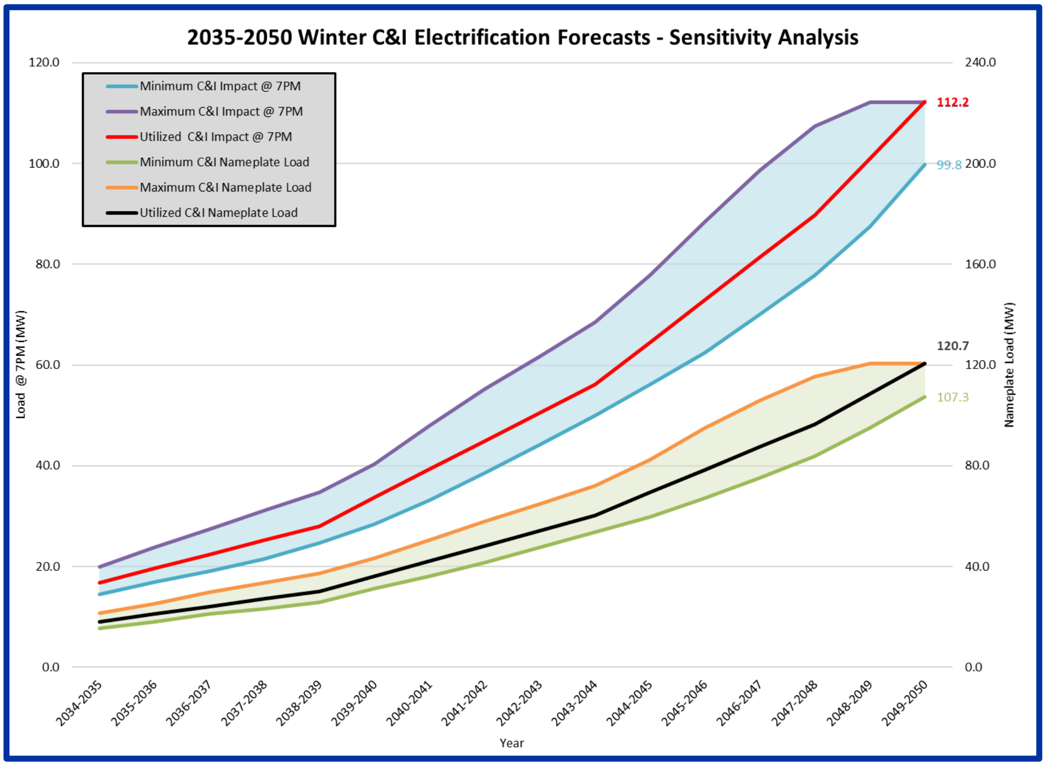

Figure 52 – 2035-2050 Winter C&I Electrification Forecasts – Sensitivity Analysis

8.2.3 Building code assumptions

This assessment does not consider changes in the building codes as the historical evolution of building codes to become more energy efficient is captured in the underlying econometric baseload forecast. Moreover, in a winter peaking future electricity system, the impact of building codes will be primarily on demand from electric heating, and the Company's load profile for electric heat pump energy usage does assume building weatherization. Changes to building codes will have the greatest impact on space heating with heat pumps. As the overall building envelope improves, smaller heat pumps can be used thus reducing the overall demand. The Company will include building code changes into future forecasts as building code changes become more prevalent and have a greater impact on existing building structures

8.2.4 Demand response scenarios – impacts on heating demand

The Company's load forecast did not assume demand response as the penetration of heat pumps is low. In addition, customer behaviors on the coldest days of the year may limit participation in the demand response program or the results of the program could be skewed by pre- or post-heating thus creating an inadvertent peak condition.

As the outside ambient temperature decreases, the coefficient of performance for the heat pump drops. In many cases, the BTU output of heat pumps can drop in half as the ambient outdoor temperature approaches 0 degrees Fahrenheit. The heat pump industry has worked to improve the coefficient of performance at lower temperatures. Continued improvements in energy efficiency programs specifically focused on the winterization of buildings may support electrification by allowing smaller heat pumps to be used. Continued improvements to building codes will also help support the use of smaller, more efficient heat pumps.

Energy storage technology may provide the opportunity for demand response associate with heat pumps. This would allow the load of the heat pump to be served from the battery as opposed to the electric system during peak winter load hours. The Company will continue to evaluate technology improvements and affordability associated with thermal and battery storage technologies, as well as hybrid heating technologies. These technologies, when paired along with heat pumps may create the opportunity for demand response during the winter peak loads. The Company will also continue to evaluate improvements in the efficiency of heat pumps and other demand response technology and will adjust our future forecasts accordingly. Demand response programs for winter heating loads will be contemplated in the next three-year energy efficiency plans.

8.3 TRANSPORT: ELECTRIC VEHICLE ASSUMPTIONS AND FORECASTS

Under the "All Options" pathway, electric vehicle charging will have a large contribution to the electric loads. Electric vehicle charging can be highly variable based upon location, time of day and amount of load. Electric vehicles can charge at any point during the day which may create challenges as well as opportunities for the electric system depending upon where and when the charging occurs. Transitioning to a high penetration of electric vehicles means EV owners have the ability to charge where they need to: work, home, stores, etc.

Electric vehicle charging in the evening, at the time of system peak loads, can create challenges and increase system peaks. Vehicle charging during the day can help to offset some of the solar generation during the shoulder months of the year when solar generation exceeds the system loads. Electric vehicle charging overnight can benefit the system by shifting charging away from the peak load hours. As the shift in system peak loads transition to winter peak system loads, the probability of a high amount of electric vehicle charging to occur early in the morning is unlikely.

As is the case with electrification forecasts, the Company used the same methodology for forecasting EV charger load for 2035 to 2050 as it did for years 2025-2034. The only change made was to assume the Company's "High Rate" or 100% of the ISO-NE EV Adoption Forecasts from 2036 to 2050.

8.3.1 Technology assumptions

The Company's EV load forecasts consider the following types of EV charging:

- Level 1 Charging – Utilizes a standard 110V wall to charge an EV in about half a day. Generally speaking, charging an EV at home adds about 3,000 kWh to annual consumption or 275 kWh per month. You'll see an increase in your monthly electricity bill that is offset by fewer trips to the gas station. The demand assumption for a Level 1 charger is 1.7kW.
- Level 2 Charging - Level 2 charging options require professional installation of a 240V outlet (similar to a clothes dryer) that enables a faster vehicle charge. Coupled with a smart EV charger that shares a data connection with the EV and the charging operator, it's an intelligent system that provides real-time information. The demand assumption for a Level 2 charger is 9.6kW.
- Direct Current Fact Charging (DCFC) - DCFC (previously referred to as Level 3 Charging), can recharge a vehicle in as little as 30 minutes, depending on the model. This commercial-level charging option is largely being explored by state/government entities along interstate highways and still faces some major challenges for large-scale implementation, including cost, compatibility and specialized infrastructure needs. The demand assumption for a Level 1 charger is 600kW.

The forecast also assumes that every EV owner will have some form of home EV Charging. 33% of EV owners will use Level 1 chargers and 67% will have Level 2 charging at home.

8.3.2 Adoption propensity assumptions

The Company also separately forecasts ten EV charging load forecasts that get incorporated into the base system load forecasts. The ISO-NE EV Adoption Forecasts by state were used as the basis for the Company's EV load projections. These ISO-NE forecasts, along with ISO-NE EV stock (registered) by state data, was used to project the number of EVs on the road and ultimately the number of EV chargers within Unitil's service territories.

ISO-NE information on the number of EVs currently registered in Massachusetts was used to estimate the current number of EVs in the service territory. Once the number of EVs was determined, the ISO-NE EV Adoption Forecasts were used to project the number of EVs. Two forecasts for each territory were created:

- High Rate – utilizes 100% of the ISO-NE EV Adoption Forecasts
- Baseline Rate – utilizes 67% of the ISO-NE EV Adoption Forecasts

Utilizing the assumptions in the section below, the estimated number of home level 1 and level 2 chargers in the service territory was calculated. EEI projections for the percentages of the total number of each type of level 2 charger allowed for the calculation of the estimated number of level 2 public and workplace chargers.

Utilization percentages (percentage of total of each type of units charging) for each hour of the day for home, public (including DC fast chargers) and workplace chargers and the assumed demand for each type of charger was then used to calculate the forecasted load due to EV charging for each hour of the day.

8.3.3 Mileage, and time of day assumptions

The Company uses the following time of day and location of charging assumptions in its forecast.

Hour of Day	Home	Public	Workplace	Hour of Day	Home	Public	Workplace
0:00	75%	25%	5%	12:00	15%	75%	60%
1:00	75%	25%	5%	13:00	15%	60%	60%
2:00	75%	25%	5%	14:00	15%	60%	60%
3:00	75%	25%	5%	15:00	25%	50%	60%
4:00	75%	25%	5%	16:00	30%	40%	50%
5:00	60%	25%	5%	17:00	40%	40%	40%
6:00	50%	35%	5%	18:00	50%	30%	15%
7:00	50%	35%	10%	19:00	60%	30%	10%
8:00	40%	50%	15%	20:00	60%	30%	5%
9:00	30%	60%	60%	21:00	60%	30%	5%
10:00	15%	75%	60%	22:00	75%	30%	5%
11:00	15%	75%	60%	23:00	75%	25%	5%

Table 71 – Hourly EV Utilization

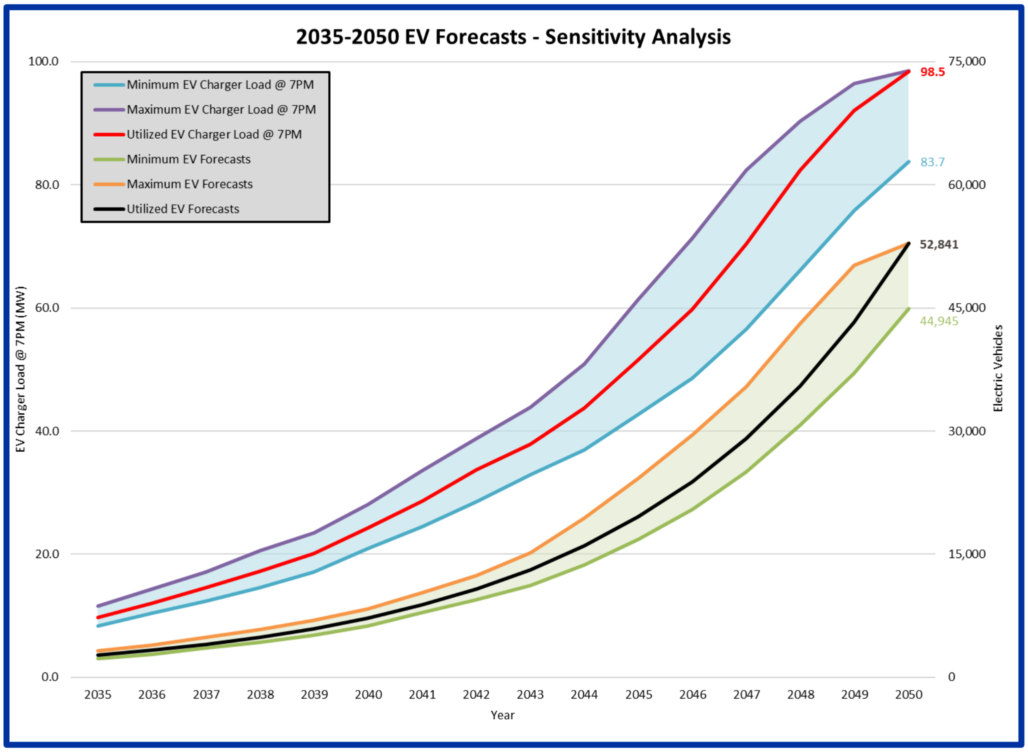

Figure 53 – 2035-2050 Year EV Forecasts – Sensitivity Analysis

8.3.4 Managed charging scenarios – Impacts on EV demand

At the present time, the Company does not have an EV managed charging program. Therefore, the load forecast does not assume managed charging. However, managed charging programs may be a necessity to control peak loading and system investment required for transportation electrification. The Company looks forward to working with the Department and stakeholders in the near future on a state-wide approach to EV managed charging and will review the status of EV charging technology and programs in future forecasts.

8.4 DER: PV/ESS – STATE INCENTIVE DRIVEN ASSUMPTIONS AND FORECASTS

The CECP identifies that distributed solar and energy storage are critical to achieving the Commonwealth's decarbonization goals. The growing penetration of variable loads and intermittent renewable resources creates a challenge for the electric system if the grid is not prepared to accept these resources. The Company's vision of the future grid is an enabling platform with the ability to interconnect a large quantity of renewable resources and other DERs.

The Company continues to experience a high penetration rate of DERs with the total capacity of generation accounting for over 70% of the peak load, and totals over 300% of the minimum daytime load. The diversity and penetration of DER installations can have the impact of deferring investments in system capacity. The Company's approach to forecasting and planning its electric system assumes an increased interest in interconnections.

Hosting capacity analysis identifies portions of the system where DERs can be installed without the need for costly system improvements. The Company has an interactive mapping system designed for customers and developers to see if their potential project is located in an area where system improvements are likely to be needed or if their project can generally proceed without the need for a costly improvement. This empowers customers to make decisions on their investment in technology. The Company's goal is to continue to identify ways to increase the hosting capacity of the system.

Locational value analysis identifies the value that a DER would have to different parts of the system. Locational value analysis is a measure of how much traditional system investment in capacity can be deferred through the installation of a DER. Reliability, capacity and availability are important factors to consider in locational value analysis.

8.4.1 Technology assumptions

The Company categorizes DER facilities into the following:

- Utility Scale DER Facility - Any DER facility with a nameplate capacity of 1,000kW or more
- Large DER Facility - Any DER facility with a nameplate capacity less than 1,000kW and up to and including 500kW
- Medium DER Facility - Any DER facility with a nameplate capacity less than 500kW and greater than 60kW
- Small DER Facility - Any DER facility with a nameplate capacity of 60kW or less

The DER/PV forecasts for 2035 to 2050 utilize the same methodology as the forecasts for 2025 to 2034. However, starting in 2035 the Company assumed the addition of one additional "large" DER/PV facility per year through 2050.

8.4.2 Adoption propensity assumptions

The process for creating DER Forecasts requires the development of ten year DER Projections for the installations of small and medium DER facilities. These DER Projections are then added to all sizes of DER facilities that are installed or approved for installation at the time the DER Forecast is developed for each distribution circuit, distribution substation transformer and the overall system. The overall system DER Forecasts also include the projected penetration of large DER facilities.

Due to the limited number and uncertainty of location of Large DER Facilities, these are not included in the circuit and substation transformer DER Projections. Similarly, Utility Scale DER Facilities are not included in circuit, substation transformer, nor system DER Forecasts. Instead these facilities will be treated similarly to how new large customer load additions are incorporated into distribution load projections in that they will be added to the DER Forecasts as actual customer applications are received per the project schedule and engineering judgement.

Distribution circuit DER Forecasts are developed using two similar methods and taking the higher result of the two methods as the ultimate DER Forecasts for each circuit.

- Method 1 – Forecast Based on Nominal DER Capacity:

  Method 1 utilizes the nominal capacity of small and medium DER facilities installed on the circuit and "normalizes" this to the three-year historical circuit peak load. A five-year and three-year historical slope is calculated based on the five-year normalized DER capacity growth on the circuit. This is done for all distribution circuits on each of Unitil's distribution operating systems.

  Based on the calculated slopes engineering judgement is used to create four growth rate ranges for each distribution operating company.

  - N – slope of zero
  - L – flat slope
  - M – moderate slope
  - A – aggressive slope

  Each circuit is assigned a historical growth rate. Based on the historical growth rates future growth rates are calculated for each of the rate types. The future rate for each type is the maximum of the three-year average and five-year average of each historical rate of that rate type.

  After reviewing the assigned historical rate type for both the three-year and five-year slopes engineering judgement is used to assign the desired future growth rate (slope) to each circuit. This slope is then used to calculate the small and medium DER Projections that are added to the total amount of DER installed and approved for installation on each circuit to get the method 1 DER Forecasts.

- Method 2 – Forecasts Based on Number of DER Facilities Installed:

  Method 2 is very much the same as method 1 with one exception. Method 2 utilizes the number of small and medium DER facilities on each circuit and "normalizes" this to the average number of customers supplied by each circuit. The same process described in method 1 is then used to project the number of small and medium units that will be installed on the circuit. The projected number of units is then multiplied by the five-year average size of small and medium units to determine the DER Projections of small and medium DER facilities for each circuit. This is added to the total amount of DER installed and approved for installation on each circuit to get the final method 2 DER Forecasts.

8.4.3 Time of day assumptions

The propensity of the DER connected (and forecast to connect) to the system is solar. Load curves from existing solar facilities are used to approximate the load curves of the new solar connections. The Company uses these load curves to estimate how the DERs will impact the overall system load curve under peak load and light load conditions.

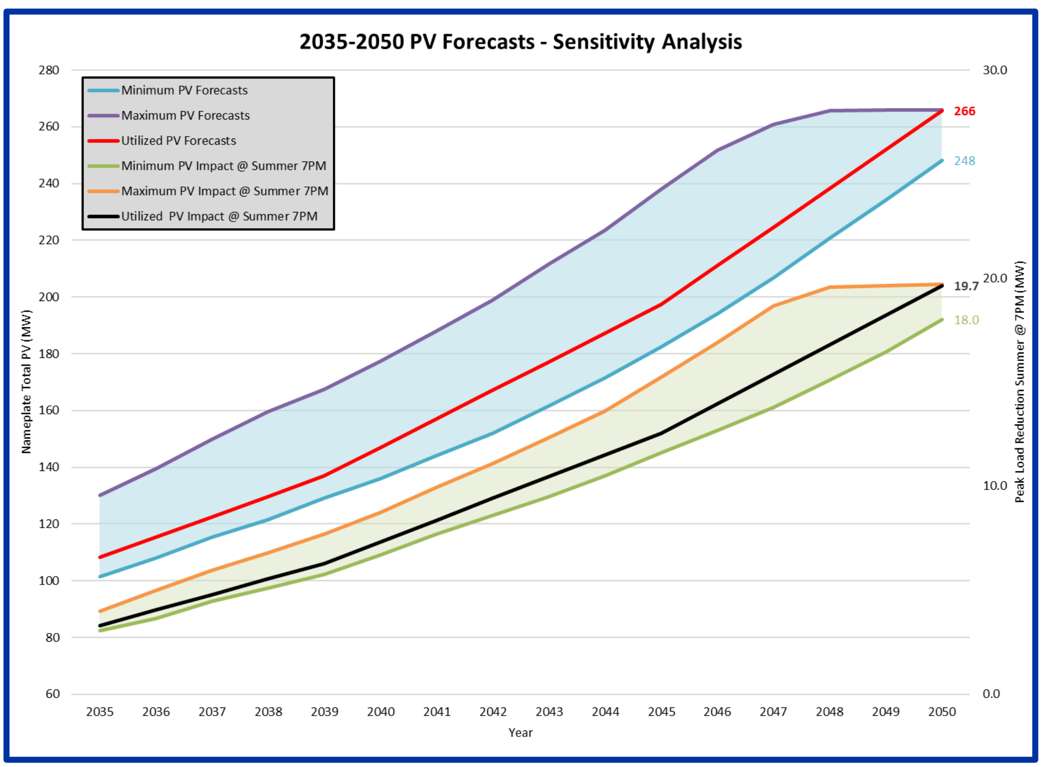

Figure 54 – 2035-2050 PV Forecasts – Sensitivity Analysis

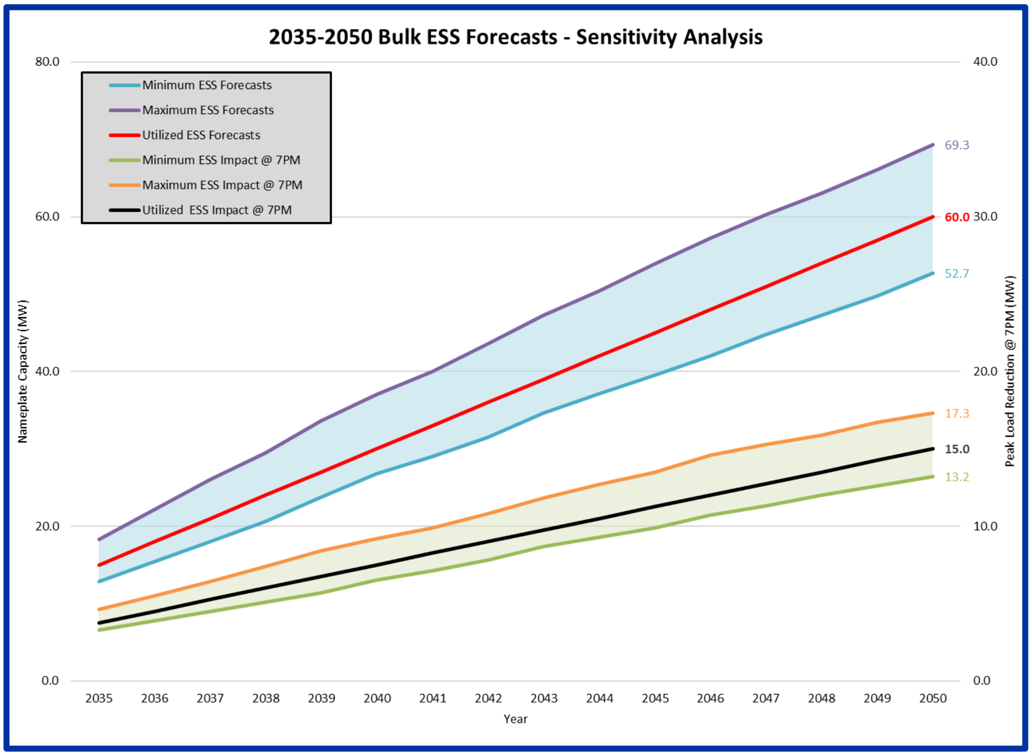

Figure 55 – 2035-2050 Bulk ESS Forecasts – Sensitivity Analysis

8.5 GRID MODERNIZATION: VVO FORECASTS

The Company considers grid modernization and the performance of VVO critical to the future of the electric distribution system. The Company includes in its planning guidelines criteria for the continued evaluation and if needed recommended changes to its VVO program to ensure it continues to provide load reducing and DER operational benefits.

The Company included the same VVO load reduction assumptions in its 2035 to 2050 load forecasts as it did in its 2025 to 2034 forecasts.

8.6 OFFSHORE WIND FORECASTS (PROCUREMENT MANDATES, GIA STATUS, POIS)

The 2022 Climate Act codifies a goal of procuring 5,600 MW of offshore wind no later than June 30, 2027. The Act also allows the Commonwealth to coordinate offshore wind solicitations with other New England states and removes the price cap that previously guided project developers' bids in response to a state-issued solicitation. The Act further sets preferences for project proposals that make commitments to, among other things, developing equitable workforce opportunities and limiting negative environmental and socioeconomic impacts.

On August 23, 2023, the Department approved the state's fourth round of offshore wind solicitations intending to procure at least 400 MW and up to 3,600 MW of offshore wind.[42]

The Company's small footprint does not lend itself to the large-scale deployment of wind. Also, the Company has a limited amount of transmission infrastructure, so transmission level projects should not have a significant impact on the Company's system.

8.7 CURRENTLY PROJECTED CLEAN ENERGY RESOURCE MIX

The Company's demand assessment is forecast to design a system to accommodate the high penetration of electric vehicles for both individual as well as medium/heavy duty EVs, as well as residential and commercial electrification, onshore and offshore wind, solar and energy storage. The Company will continue to re-evaluate its forecasts to make further improvements as adoption rates change in the near and mid-term.

[42] D.P.U. 23-42, *Joint Petition of the Massachusetts Department of Energy Resources et al*, Order at 91 (August 23, 2023).

9 2035 - 2050 SOLUTION SET – BUILDING A DECARBONIZED FUTURE

The first ten years of electric sector modernization is rather clear and focuses on the capacity and resiliency of the electric system to meet the forecasted demands of electrification and DER integration as well to increase the resiliency of the electric system to withstand increasing major storm events caused by climate change. Beyond 2035, there are many different pathways that can be taken to support the State's decarbonization goals. Those pathways may need to consider: 1) the installation of behind the meter technology and incentives to empower users to take control of their energy usage; 2) the continued improvement in building energy efficiency standards and heat pump efficiencies; 3) continued deployment of EV charging and incentive mechanisms to attract participation; 4) load management and incentive designs; and 5) battery storage charge management.

In addition to the advancement of behind the meter technologies and incentive programs past 2035, the electric system is still faced with the challenge of aging substation infrastructure. The replacement of this equipment provides the opportunity to continue to increase the overall load and DER hosting capacity of the system while addressing aging infrastructure. Non-wires alternatives will hopefully see improvements in reliability, capacity and availability to the point where they may become cost-effective alternatives to traditional investment. Technologies to decarbonize the gas distribution system may continue to improve the cost, availability and safety of the alternatives. System optimization will continue with increased monitoring and control of the resources connected to the electric system. Incentive mechanisms will be in place to incentive customers to allow their equipment to be operated to the benefit of the system.

9.1 CLEAN ENERGY SOLUTIONS INCLUDING BEHIND THE METER INCENTIVE DESIGN SCENARIOS (IMPACT ON ELECTRIFICATION DEMAND)

Based upon the load forecast presented in this Plan, system loads are forecast to increase by 3 to 4 times between now and 2050. Some of the electrification can be offset with DERs, but the system must be designed to reliably serve the increase in demand. Innovative rate designs and pricing structures will be required to prevent an increase in load on the electric system due to pricing incentives.

9.1.1 Buildings: Winter demand response scenarios and associated preliminary incentive designs

Heat pumps will have the effect of lowering summer peak load, but will tend to increase winter peak loads. As demonstrated in the load forecast, the Company expects to transition from a summer peaking system to a winter peaking system by 2033. This transition in system peak is driven by the electrification of heating loads traditionally served by fossil fuels as well as electric vehicle charging.

The American Council for an Energy-Efficient Economy ("ACEEE"), a nonprofit research organization, completed a report[43] that found that for better-sealed homes, higher-performing heat pumps and grid interactive measures like water-heating systems that heat water at lower demand times could reduce the winter peak by up to 12%.

As the outside ambient temperature decreases, the coefficient of performance for the heat pump drops. In many cases, the BTU output of heat pumps can drop in half as the ambient outdoor temperature approaches 0 degrees Fahrenheit. The heat pump industry has worked to improve the coefficient of performance at lower temperatures. Continued improvements in energy efficiency programs specifically focused on the winterization of buildings may support electrification by allowing smaller heat pumps to be used. Continued improvements to building codes will also help support the use of smaller, more efficient heat pumps.

Energy storage technology may provide the opportunity for demand response associated with heat pumps. This would allow the load of the heat pump to be served from the battery as opposed to the electric system during peak winter load hours. The Company will continue to evaluate technology improvements and affordability associated with thermal and battery storage technologies, as well as hybrid heating technologies. These technologies, when paired along with heat pumps may create the opportunity for demand response during the winter peak loads. The Company will also continue to evaluate improvements in the efficiency of heat pumps and other demand response technology and will adjust our future forecasts accordingly.

Innovative rate designs will be required to manage or mitigate loads during winter peak times. Those rate designs should incentivize customers to reduce loads (i.e. turning off the heat pump or increasing the setpoint) during certain periods of time. Another approach is for the Company to control an aggregated grouping of heat pumps and compensate customers for participating in the program.

[43] https://www.aceee.org/research-report/u2101 - dated April 15, 2021

9.1.2 Transport: Electric vehicle charging demand management scenarios

The Company has approved residential electric vehicle TOU rates. These rates became effective April 1, 2023. Service under this schedule is specifically limited to residential customers who take service restricted to charging a battery electric vehicle or plug-in hybrid electric vehicle via a recharging outlet at the customer's premises. This schedule is not available to customers with a conventional charge sustaining (battery recharged solely from the vehicle's on-board generator) hybrid EV.

Energy supply is available on a time of use basis for the Company's Basic Service customers[44]. For the purpose of billing, "On-Peak" is defined to be between the hours of 3:00 P.M. and 8:00 P.M. (local time) for all non-holiday weekdays, Monday through Friday. "Mid-Peak" is defined to be between the hours of 6:00 A.M. to 3:00 P.M. daily Monday through Friday, except holidays. "Off-Peak" is defined to be between the hours of 8:00 P.M. to 6:00 A.M. daily Monday through Friday and all day on holidays and weekends.

The Company's EV TOU rate (EV-RES) took effect only recently, and customer adoption continues to evolve. At this point, the Company has not completed analysis on the optimal $/kW incentives to attract participation or the ongoing cents/kW incentives to subsidize O&M (especially in EJCs). As participation continues to grow, the Company will continue to carefully evaluate the TOU model for this purpose.

An unintended consequence of the current TOU design is that all vehicles could charge at an off-peak time (e.g., 8:00pm). Demand management[45] for EV charging may be required to "smooth out" the charging load associated with "off-peak" charging. Demand management for EVs will need to include not only penalties for charging at certain times, but incentives for discharging back to the grid at certain times.

On a small scale, this is already accomplished at a charging station. When a second car plugs into a charging station, the charger automatically adjusts the charging of the first vehicle so as not overload the charger. This concept may be used in the future as part of a DERMS or other control scheme that can use real time circuit loads to provide information to participating vehicle chargers and control loads on a circuit or substation scale.

[44] At this time, customers on competitive electric supply or in a municipal aggregation may only participate in time-varying distribution and transmission charges, as applicable.
[45] Demand management is the balancing of loads at any given time to keep overall loads below a certain capacity.

V2G, also referred to as managed charging, is a technology that allows electric vehicles to charge when the electric system has excess capacity and to discharge or provide a source into the electric system when the system may need more capacity. V2G can have the impact of helping the electric system balance more and more renewable energy and EV load. The Company does not have a V2G program at this time. However, a V2G strategy will be required to address the large increases in expected load as EV adoption increases.

At this point, the future EV load forecasts do not include the impacts a V2G program may have on the electric system. The Company will continue to evaluate the most up to date information on V2G technologies as part of its annual forecast and determine the impact V2G may have on the EV load forecasts.

9.1.3 Other Load Management Response Scenarios and Associated Preliminary Incentive Designs

Innovative rate design is driven by timely and accurate data. The Company's Advanced Metering Infrastructure, Meter Data Management system and Customer Information System provide the tools required to provide timely and accurate metering data for many different types of innovative rate designs and coupled with data sharing platforms, allow customers to make informed energy choices.

Innovative rates should be based on cost-of-service rate design principles to ensure economic efficiency and limit cost shifting. Critical Peak Pricing ("CPP") and demand reduction approaches are also worthy of consideration in addition to tariff-based TOU rates.

Marginal energy costs are typically driven by wholesale electric market (ISO-NE in this case) factors and may not fluctuate for different customer segments. Existing load management programs are focused on reducing load at the ISO-NE peak. The ISO-NE peak load may or may not coincide with a location specific distribution capacity constraint. Any demand management program designed for the distribution system must ensure that the resources are available when the distribution system requires the resource.

A utility's distribution-related costs are fixed in nature and are incurred to meet customers' non-coincident peak demands and do not necessarily exhibit time-varying cost characteristics. In most cases, demand charges for C&I customers better reflect the manner in which a utility's costs are incurred to serve such larger customers. Incremental loads may require new transformers, service lines and meter upgrades. Instances may also exist where the addition of loads would require an upstream feeder and/or substation upgrade.

The Company believes the rate design options for any type of electric load should be designed to promote the efficient use of the utility's electric system resources and reduce costs for all utility customers. Rate options must provide proper price signals and influence customer behavior in a manner that creates beneficial outcomes for the customer (through lower rates and electric bills) and for the utility (through a reduction in system costs over time). To achieve these objectives, the design of the rate options should only reflect system costs that are time-varying in nature, and provide customers a cost-based price signal through the rate design. The time-varying costs should drive the desired shape of the utility's system load curve and not simply represent a preconceived outcome based on non-cost or qualitative presumptions.

At the same time, it is also necessary to understand and evaluate how customers are responding to the utility's TOU rate options in order to make periodic refinements to the TOU rate design and identify how the utility's load shape and resulting costs will likely change over time. For example, some customers may find certain TOU rate design options to possess overly long peak time periods, precluding those customers from responding to the TOU rate in a meaningful way. In addition, some jurisdictions have designed TOU rates to create a significant peak to off-peak rate differential to increase the likelihood of a positive customer response without recognizing that the underlying costs of the utility are not accurately reflected by the rate design. In that case, a rate benefit is afforded to customers who can change their electric usage patterns even though the utility does not experience a corresponding reduction in cost. This may be deemed desirable for non-cost causative objectives, such as supporting technology adoption, gaining an understanding of consumer behavior, and insights into grid operations and future investment requirements by the utility.

Innovative rate design considers the effect that technology adoption will have on the electric distribution system and subsequent system planning and investment. Technology adoption rates should be forecast over the coming years and integrate these loads into planning studies and load forecasts. Possible changes to engineering and construction standards may be warranted to ensure reliability, safety, and appropriate equipment sizing.

The design of electric services may need to change as well, such as shorter distances and increased conductor size to address voltage drop concerns. Ongoing capital budgeting may need to accommodate early replacement of current infrastructure that is undersized and unable to accommodate new customer loads. Additionally, the installation of interval metering should be considered for increasingly dynamic loads and generation that have the potential to export energy onto the distribution system and necessitate more granular planning analyses.

Innovative rate design may also include make-ready programs, charging incentives, and behind the meter partnerships with third parties. Data sharing between the utility, customers and third parties can also be a solution to overcoming barriers to customer adoption. The Company continues to work on data sharing tools and standards (e.g., Green Button). Home energy management systems have become widely available, with lower costs over time. Data sharing standards and platforms should be considered that benefit the customer, the utility, society at large, and third-party vendors.

9.1.4 Battery Storage Charge Management and Associated Preliminary Incentive Designs

As stated above, demand management for battery charging may be required to “smooth out” the charging load associated with “off-peak” charging. Demand management for batteries will need to include not only penalties for charging at certain times, but incentives for discharging back to the grid at certain times. In order to be considered a NWA, monitoring and control of such assets by the Company is an important factor to ensure the resources will be available when the distribution system needs it.

In addition, battery storage can be paired with solar to reduce interconnection costs by reducing the amount of generation pushed onto the system at times of light load. In these cases, the battery is never charging from the gird, only from the solar facility. The battery can then be used to serve load when the solar facility is not operating or when the grid may need the resource. In order to be considered a NWA, monitoring and control of such assets by the Company is an important factor to ensure the resources will be available when the distribution system needs it.

As the costs of FTM and BTM batteries continue to decrease the adoption will increase. Batteries offer a reliable resource the electric system can depend upon if they can be controlled in a way to ensure they are available when called upon.

In addition to the discussion above, on October 31, 2023 the Company filed draft Operational Parameters for Energy Storage Systems Tariff, filed pursuant to the Act Driving Clean Energy and Offshore Wind. Section 72 of the Act directs the Commonwealth’s EDCs to file with the Department, on or before October 31, 2023, “at least one electric rate tariff, which addresses operational parameters, to apply to energy storage systems interconnected to their distribution network.” The Company worked in collaboration with the other EDCs to solicit stakeholder input and develop a tariff meeting the requirements of the Act, submitted a tariff for the Department's consideration and approval.

The Operational Parameters Tariff sets operational and technical parameters for distribution-connected ESS, including: (1) use of Dispatch Limiting Schedules; (2) limits on ESS capacity based on feeder operating voltage and feeder and substation loading as a percent of their ratings; and (3) DERMS readiness. The Operational Parameters Tariff also addresses rate assignments for standalone ESS that do not participate in the wholesale market. The Company intends to submit a proposal to FERC for a wholesale distribution rate governing rates for ESS that are interconnected to the distribution system and plan to participate in the wholesale market as required by the Act.

The objective behind the Operational Parameters Tariff is to formalize the technical requirements for ESS and to create a sustainable process to enable the Commonwealth's clean energy goals and further development of the ESS market. The Operational Parameters Tariff moves toward interconnection behaviors, designs, and locations that may best support advancement toward state energy targets and will lay the foundation for DERMS implementation. This is a good first step for energy storage systems to be operated in a manner that can be considered as an alternative to traditional investments.

9.2 AGGREGATE SUBSTATION NEEDS

The Company evaluated the adequacy of major electric system components at the load levels included in Section 8 above. This review assumed the proposed projects in section 6.4 are complete. The following table summarizes the system deficiencies identified through this process. The table is sorted by year. The system constraint is listed in the year when it first violates planning criteria. The loading constraints listed below assume the projects proposed from 2025 to 2034 are complete.

Year	System Constraint	Circumstances
2035	Rindge Road – 13.8kV Regulators – Loaded Above Normal Rating	Basecase – Reverse Powerflow
2036	Townsend S/S – 15T1, 69kV-13.8kV, 10.5MVA Transformer – Loaded Above Normal Rating	Basecase
	Sawyer Passway S/S – Circuit 22W1 Mainline Conductor – Loaded Above Normal	Basecase
2037	Flagg Pond S/S – 4T1, 115kV-69kV, 100MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of Flagg Pond 4T2

Year	System Constraint	Circumstances
	Flagg Pond S/S – 4T2, 115kV-69kV, 100MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of Flagg Pond 4T1
	Princeton Road S/S – 50T3, 69kV-13.8kV, 20MVA Transformer – Loaded Above Normal Rating	Basecase
2038	Pleasant Street S/S – 39T1, 69kV-13.8kV, 14MVA Transformer – Loaded Above Normal Rating	Basecase – Reverse Powerflow
2040	01 Line – Flagg Pond S/S to Summer Street S/S – Loaded Above Emergency Rating	N-1 – Loss of 02 Line from Flagg Pond S/S to Summer Street S/S
	02 Line – Flagg Pond S/S to Summer Street S/S – Loaded Above Emergency Rating	N-1 – Loss of 01 Line from Flagg Pond S/S to Summer Street S/S
	Summer Street S/S – 40T1, 69kV-13.8kV, 35MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of 06 Line from Summer Street S/S to Sawyer Passway S/S
2041	West Townsend S/S – 39T1, 69kV-13.8kV, 10.5MVA Transformer – Loaded Above Normal Rating	Basecase
2042	Canton Street S/S – 11T1, 69kV-13.8kV, 14MVA Transformer – Loaded Above Normal Rating	Basecase
2043	08 Line – Pleasant Street S/S to Lunenburg S/S – Loaded Above Emergency Rating	N-1 – Loss of 09 Line from Summer Street to West Townsend
	09 Line – Pleasant Street S/S to Lunenburg S/S – Loaded Above Emergency Rating	N-1 – Loss of 08 Line from Summer Street to Townsend
	Princeton Road S/S – 50T2, 69kV-13.8kV, 20MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of Princeton Road 50T3
2044	Summer Street S/S – Circuit 40W40 Mainline Conductor – Loaded Above Normal	Basecase
	Beech Street S/S – 1T1, 69kV-13.8kV, 22MVA Transformer – Loaded Above Normal Rating	Basecase
2045	08 Line – Lunenburg S/S to Townsend S/S – Loaded Above Emergency Rating	N-1 – Loss of 09 Line from Summer Street to West Townsend
	09 Line – Lunenburg S/S to West Townsend S/S – Loaded Above Emergency Rating	N-1 – Loss of 08 Line from Summer Street to Townsend
	Sawyer Passway S/S – 22T1 and 22T2, 69kV-13.8kV, 20MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of Summer Street S/S 40T1 Transformer
	Princeton Road S/S – Circuit 50W56 Mainline Conductor – Loaded Above Normal	Basecase
2046	River Street S/S – 25T1, 69kV-13.8kV, 14MVA Transformer – Loaded Above Normal Rating	Basecase
2047	Beech Street S/S – Circuit 1W2 Mainline Conductor – Loaded Above Normal	Basecase
2049	West Townsend S/S – Circuit 39W18 Mainline Conductor – Loaded Above Normal	Basecase
2050	08 Line – Summer Street S/S to Pleasant Street S/S – Loaded Above Emergency Rating	N-1 – Loss of 09 Line from Summer Street to West Townsend

Year	System Constraint	Circumstances
	09 Line – Summer Street S/S to Pleasant Street S/S – Loaded Above Emergency Rating	N-1 – Loss of 08 Line from Summer Street to Townsend
	Townsend S/S – Circuit 15W16 Mainline Conductor – Loaded Above Normal	Basecase

Table 72 – System Constraints from 2035-2050

With the exception of distribution mainline circuit conductors this review did not include the evaluation of other distribution equipment. Although significant upgrades should be anticipated on the distribution circuits themselves, the scope and timing of these upgrades will be more dependent on the physical location of load and which of the upgrades have been implemented at the time.

The projects detailed below address the identified constraints are based on a holistic plan to serve its customers through 2050 and beyond. The timing and need for these projects will be evaluated on an annual basis and work on these projects will only commence when load forecasts and/or planning efforts determine they are needed.

Given the extent of the electric system upgrades required to meet the forecasted load levels consideration should be given to a possible change in distribution circuit operating voltage in some or all areas from 15kV to higher voltage such as 35kV, similar to what was done decades ago during the last great electric system load increase when many circuits were converted from 4kV to 15kV.

9.2.1 Establish 2nd Circuit at Rindge Road - 2035

The loading on circuit 35W36 is forecast to exceed planning criteria in 2035. This project will reconfigure circuit 35W36 at Rindge Road S/S and establish a second 13.8kV circuit. The new circuit terminal will consist of a circuit recloser and set of voltage regulators. A second circuit is designed to improve reliability in addition to adding capacity to the area.

Project specific transmission studies are not typically needed for upgrades internal to the FGE system that do not directly impact, extend and/or tap transmission infrastructure. This project is not anticipated to require detailed transmission evaluations or transmission level investments. Load forecasts that the Company provides to the local transmission service provider typically include the added load driving system improvements, such as this.

9.2.2 Townsend Substation Capacity Additions - 2036

To address the forecasted loading constraint associated with the 15T1 transformer Townsend substation capacity will be increased. Construction will include the installation of two 30MVA (or larger), 69kV to 13.8kV transformers with LTCs and the removal of the existing 10.5MVA unit. Two 13.8kV circuit positions will be added, bringing the total number of circuits to six, three supplied via each transformer.

Distribution work will be performed to split circuit 15W16 and to extend a second circuit towards Ashby to allow for the temporary transfer of load from West Townsend S/S to Townsend S/S, deferring the West Townsend S/S 39T1 transformer loading constraint from to approximately 2045.

Project specific transmission studies are not typically needed for upgrades internal to the FGE system that do not directly impact, extend and/or tap transmission infrastructure. This project is not anticipated to require detailed transmission evaluations or transmission level investments. Load forecasts that the Company provides to the local transmission service provider typically include the added load driving system improvements, such as this.

This project is anticipated to provide sufficient capacity to allow load to be transferred from West Townsend substation to Townsend substation addressing West Townsend 39T1 transformer loading until approximately 2044.

9.2.3 Install New Circuit and Split Circuit 22W1 - 2036

The loading on circuit 22W1 is forecast to exceed planning criteria in 2036. Install a new circuit from Sawyer Passway S/S to Mount Vernon Street. The new circuit will serve 22W1 loads from Sawyer Passway up to and including Mount Vernon Street and 22W1 will continue to serve loads beyond Mount Vernon Street. An alternative to this project is to reconductor underground portion of the 22W1 mainline.

A review of existing conduit and required new conduit and vaults will need to performed to determine the extents of both options

Project specific transmission studies are not typically needed for upgrades internal to the FGE system that do not directly impact, extend and/or tap transmission infrastructure. This project is not anticipated to require detailed transmission evaluations or transmission level investments. Load forecasts that the Company provides to the local transmission service provider typically include the added load driving system improvements, such as this.

9.2.4 Flagg Pond Capacity Additions - 2037

Installation of additional capacity at Flagg Pond S/S. This includes the replacement of the two existing Flagg Pond transformers as well as the spare transformer with 115kV-69kV, 200MVA transformers with LTCs. This project will also include the upgrade of the 69kV bus and breakers to accommodate the additional transformer and line capacity.

A variation of this project is to install a third 100MVA, 115kV to 69kV transformer with LTC and replace the existing three transformers with LTC units. Modifications to both the Flagg Pond 115kV and 69kV ring buses would be required to accommodate a third transformer.

The decision between an additional transformer vs larger transformers will require detailed design and technical review to evaluate equipment requirements, availability and design and protection considerations.

Installing additional capacity at Flagg Pond is currently being proposed in 2037 rather than the new Lunenburg/Summer Street Area Supply below as it allows the Company to distribute spending between years while working towards the Lunenburg/Summer Street Area Supply.

This project is expected to address loading constraints associated with Flagg Pond substation until approximately 2042.

Flagg Pond is identified as a Pool Transmission Facility. Upgrades made to this substation are transmission level investments and are expected to require detailed transmission evaluations.

9.2.5 Replace Princeton Road 50T3 Transformer - 2037

Replace the Princeton Road 50T3 Transformer with a 30MVA (or larger), 69kV to 13.8kV transformer with LTC.

Project specific transmission studies are not typically needed for upgrades internal to the Unitil system that do not directly impact, extend and/or tap transmission infrastructure. This project is not anticipated to require detailed transmission evaluations or transmission level investments. Load forecasts that the Company provides to the local transmission service provider typically include the added load driving system improvements, such as this.

9.2.6 Pleasant Street Substation Capacity Additions - 2038

Pleasant Street substation capacity will be increased. Construction will include the installation of a new 30MVA (or larger), 69kV to 13.8kV transformer with LTC and populating the fourth circuit position at Pleasant Street S/S.

Distribution work will be performed to distribute load between the four circuits and the two transformers.

Project specific transmission studies are not typically needed for upgrades internal to the Unitil system that do not directly impact, extend and/or tap transmission infrastructure. This project is not anticipated to require detailed transmission evaluations or transmission level investments. Load forecasts that the Company provides to the local transmission service provider typically include the added load driving system improvements, such as this.

9.2.7 01 and 02 Line Capacity Additions - 2040

The 01 and 02 lines from Flagg Pond substation to Summer Street substation will be rebuilt with larger conductor (something larger than is typically utilized by FG&E). The summer Street 69kV bus including the 01 and 02 breaker positions would be upgraded to accommodate the additional capacity.

These lines will be constructed in a “double-circuit” configuration to accommodate future 115kV transmission lines (one each pole) between Flagg Pond and a new Lunenburg/Summer Street area substation in the future.

Similar to the Flagg Pond S/S upgrades above the reconductoring of the 01 and 02 lines is currently being proposed opposed to the new Lunenburg/Summer Street Area Supply below. This allows the Company to distribute spending between years while working towards the Lunenburg/Summer Street Area Supply.

Flagg Pond is identified as a transmission asset. Upgrades made to these lines are local transmission level investments and are expected to require detailed transmission evaluations.

9.2.8 Summer Street Substation Capacity Additions - 2040

Summer Street substation capacity will be increased. Construction will include the installation of two 30MVA (or larger), 69kV to 13.8kV transformers with LTCs and the removal of the existing 35MVA unit (due to anticipated condition concerns).

The Summer Street 69kV bus will need to be modified to accommodate the second transformer as well as a future sixth 69kV line.

This will set the stage for the future removal of the 1303/1309 lines to accommodate two additional 13.8kV distribution circuits.

This project is expected to allow Summer Street substation to continue to restore Sawyer Passway substation for the loss of the 06 line until 2045. This project is also expected to address loading concerns associated with Sawyer Passway for loss of the Summer Street 40T1 transformer through 2050.

A small portion of this project is expected to be transmission level investments, because the 01 and 02 line positions at Summer Street substation are classified as local transmission assets. Transmission upgrades beyond those directly associated with 01 and 02 line positions are not expected to be required to support this project.

9.2.9 Construction New Lunenburg/Summer Street Supply - 2042

The capacity additions at Flagg Pond proposed in 2037 and forecasted to be exceeded in approximately 2042. To address these constraints a new 115kV to 69kV supply substation will be constructed in the vicinity of the Lunenburg Tap. Construction to include the installation of three (one spare) 200MVA, 115kV to 69kV transformers with LTC, a 115kV bus and a 69kV bus. The 115 kV bus will accommodate the two 115kV supply lines and two transformer taps. The 69 kV bus will accommodate the two transformer taps and six 69kV lines.

The 115 kV bus will be supplied via two new 115kV lines constructed from Flagg Pond substation to the new supply substation. The new lines will be overbuilt on the existing 01/02 lines and 08/09 lines. The 01/02 and 08/09 will remain and supply the existing distribution substations at 69kV. The Flagg Pond 115kV bus will need to be expanded to accommodate the two new 115kV lines.

The 69kV bus will serve the 08 and 09 lines towards Summer Street substation, the 08 and 09 lines Lunenburg Tap and the 08 and 09 lines towards Townsend and West Townsend.

This project is expected to require detailed transmission evaluations and transmission level investments. Once the proposed location of the substation is determined the Company will submit transmission connection applications. ISO-NE and the transmission service provider will perform the necessary analysis to determine the level of transmission upgrades that will be required to support this project. This review will include the necessary analysis to confirm that the transmission system will have the capacity to adequately serve the proposed substation well into future.

This project is expected to address loading constraints associated with 115kV supply into the FG&E system as well as the 01/02 and 08/09 lines from Pleasant Street to Lunenburg through 2050.

At this time, it is assumed that the new 115kV lines as well as a majority of the new substation will be classified as transmission infrastructure.

9.2.10 Beech Street Tap Substation – 2042

To address loading constraints associated with Canton Street substation a new 69kV to 13.8kV substation will be constructed in the vicinity of the River Street Tap. Construction to include a 69kV bus with two incoming lines, four outgoing lines and two transformer taps. Two 30MVA (or larger), 69kV to 13.8kV transformer will be installed to supply four 13.8kV circuits.

Two of the 13.8kV circuits will head west towards the Massachusetts Turnpike to supply portions of the Princeton Road and River Street circuits. The two other circuits will head north and east to supply portions of River Street and Canton Street substation load.

This project is expected to address Canton Street constraints until 2047 and Beech Street loading through 2050. Additionally, this project is expected to address loading constraints associated with Princeton Road substation 50T2 as well as planning violations associated with the 50W56 mainline conductor.

The 01 and 02 lines and the Beech Street tap are classified as a local transmission asset. Therefore, the 69kV portions the proposed substation are anticipated to be transmission level investments. Transmission upgrades beyond those directly associated with 01 and 02 lines and the Beech Street tap are not expected to be required to support this project.

9.2.11 New Rindge Road and Ashby Area Substations – 2044

To address loading constraints associated with West Townsend S/S as well as voltage and loading constraints in the Ashby area a new 69kV to 13.8kV substation will be constructed. One substation will be constructed at Rindge Road Tap and will consist of one 30MVA (or larger), 69kV to 13.8kV transformer with LTC and four 13.8kV circuit positions. The construction of this substation is required to accommodate the conversion of 1341 line from 13.8kV to 69kV operation.

The second substation will be constructed in the vicinity of the Main Street/New Ipswich Road intersection in Ashby. This substation will consist of two 30MVA (or larger), 69kV to 13.8kV transformers with LTC that supply six 13.8kV circuits.

In order to supply these two substations a 69kV line “loop” will need be installed between River Street substation and Wallace Road (along City/Town Road or in ROW), Wallace Road and Rindge Road (existing 1341 will be converted to 69kV), Rindge Road and Main Street/New Ipswich Road (along City/Town Road or in ROW) and between Main Street/New Ipswich Road and West Townsend S/S (along City/Town Road or in ROW).

To accommodate the new 69 kV line the 09 line from Lunenburg to West Townsend will be reconductored and the West Townsend 69kV bus will be reconfigured to accommodate the new line.

This project is expected to address West Townsend substation constraints until 2050 as well as the 08/09 line from Lunenburg to Townsend/West Townsend and circuit 39W18 and 40W40 mainline constraints through 2050.

Project specific transmission studies are not typically needed for upgrades internal to the Unitil system that do not directly impact, extend and/or tap transmission infrastructure. This project is not anticipated to require detailed transmission evaluations or transmission level investments. Load forecasts that the Company provides to the local transmission service provider typically include the added load driving system improvements, such as this.

9.2.12 Replace Lunenburg 30T1 Transformer - 2044

The capacity of Lunenburg substation, with one 30MVA and one 7.5/10.5MVA transformer, is expected to be exceeded in 2044. The existing Lunenburg Street 30T1 Transformer will be replaced with a 30MVA (or larger), 69kV to 13.8kV transformer with LTC.

Project specific transmission studies are not typically needed for upgrades internal to the Unitil system that do not directly impact, extend and/or tap transmission infrastructure. This project is not anticipated to require detailed transmission evaluations or transmission level investments. Load forecasts that the Company provides to the local transmission service provider typically include the added load driving system improvements, such as this.

9.2.13 Construction 2nd 69kV Line between Summer S/S and Sawyer Passway - 2045

The capacity of Summer Street substation is expected to be exceeded after switching to restore all load for loss of the 06 line in 2045. To address this constraint a 2nd 69kV sub-transmission line between Summer Street substation and Sawyer Passway substation will be constructed. The new line will be constructed in place of the existing 1303 and 1309 lines.

This will provide four additional 13.8kV circuit positions in the “central” Fitchburg area, two at Sawyer Passway substation and two at Summer Street substation.

Project specific transmission studies are not typically needed for upgrades internal to the Unitil system that do not directly impact, extend and/or tap transmission infrastructure. This project is not anticipated to require detailed transmission evaluations or transmission level investments. Load forecasts that the Company provides to the local transmission service provider typically include the added load driving system improvements, such as this.

9.2.14 Replace River Street 25T1 Transformer - 2046

Replace the existing River Street 25T1 Transformer with a 30MVA (or larger), 69kV to 13.8kV transformer with LTC.

In addition to addressing River Street 25T1 transformer loading this project is also expected to alleviate the loading concern associated with the 1W2 mainline.

Project specific transmission studies are not typically needed for upgrades internal to the Unitil system that do not directly impact, extend and/or tap transmission infrastructure. This project is not anticipated to require detailed transmission evaluations or transmission level investments. Load forecasts that the Company provides to the local transmission service provider typically include the added load driving system improvements, such as this.

9.2.15 Canton Street Substation Capacity Additions - 2047

Canton Street substation capacity will be increased. Construction will include the installation of a new 30MVA (or larger), 69kV to 13.8kV transformer with LTC. Construction to include the installation of a fourth circuit position at Canton Street S/S.

Depending on the ultimate design of the upgrades and with 01 and 02 lines being classified as a local transmission assets portions of the project’s scope and costs could be transmission level investments. Transmission upgrades beyond those directly associated with 01 and 02 lines are not expected to be required to support this project.

9.2.16 Replace West Townsend 39T1 Transformer - 2050

Replace the existing West Townsend 39T1 Transformer with a 30MVA (or larger), 69kV to 13.8kV transformer with LTC.

In addition to addressing West Townsend 39T1 transformer loading this project is also expected to alleviate the loading concern associated with the 15W16 mainline.

Project specific transmission studies are not typically needed for upgrades internal to the Unitil system that do not directly impact, extend and/or tap transmission infrastructure. This project is not anticipated to require detailed transmission evaluations or transmission level investments. Load forecasts that the Company provides to the local transmission service provider typically include the added load driving system improvements, such as this.

9.3 NON-WIRES ALTERNATIVES – IMPACT ON SUBSTATION DEFERRAL

Project evaluation is an integral component of maintaining a cost-effective system that ensures safe and reliable electric service. A consistent process and documentation criteria for project evaluation is required for the success of the planning process.

For the purposes of this ESMP, "non wires alternatives" are defined as "technologies or operating practices intended to reduce grid congestion and manage peak demand to offset a utility's need to make additional investments in conventional assets like wires, poles, and substations. The technologies can include distributed energy resources, such as microgrids or batteries, and practices and programs focused on load management, demand response or energy efficiency."[46]

There are many different NWA technologies and programs that are considered as part of the NWA review process. Considerations for FTM and BTM technologies, reliability and availability, monitoring and control, cost impact, and feasibility to implement. The Company considers different use cases when evaluating NWAs:

- Load Reducers – The Company's load forecast and demand assessment forecasts load adders and load reducers. Load reducers are assumed to be in place and providing a load reduction when the system needs it. Load reducers can include energy efficiency and

[46] Exploring Non-Wire Alternatives in a Wired Industry | American Public Power Association

solar PV. These load reducers lower the forecasts which in turn delays the timing of the system constraints.

- Non-Traditional Investments – In addition to the forecasted load reducers, there is the opportunity for individual, non-traditional investments to alleviate the system constraints. For instance, utility scale energy storage or other technologies that have a high reliability and availability to address system constraint. An example of this type of investment is the Company's Townsend Substation Battery described in more detail below. These types of investments tend to be owned and operated by the Company.
- DER as a Grid Service – This type of investment contemplates a group of DER providing a load reduction service when the system needs it. These DERs are generally customer owned, therefore monitoring, control and operating agreements may be required to ensure the reliability and availability of the resource. The timeframe to implement this type of investment can take longer, therefore system planning is required to identify future locations where this type of investment can provide value.
- Bridge to Wires – In some cases, the load forecast in combination with system planning may identify a project need in the near term. The challenge may arise that the traditional investment cannot be constructed in time to meet the system need due to land procurement, facility siting, permitting, design, equipment procurement and construction. In this case, existing resources may be called upon to address a locational constraint in the near term until the traditional investment can be constructed. These resources could include, demand response, battery storage, or other resources that can reliably reduce loading at the time the system needs it. These resources are typically owned by a third party.
- Flexible Interconnections – There are instances when customer owned DER may cause constraints on the electric system at certain times of the year, but may have the ability to operate safely at other times of the year. One solution is to require the DER to address the system constraint. Another solution is to allow the DER to interconnect and operate when the system can support the DER and disconnect when the system cannot support the DER. In these cases, remote monitoring and control by the utility, can be implemented and the resource can be operated in a manner that does not create constraints on the system. This approach allows for a faster and less costly path to interconnection. The Company does not currently have a flexible interconnection process or procedure, but will evaluate implementing one.

In 2019, the Company developed a process to evaluate non-wires alternatives for projects exceeding $500,000 in cost that are identified on the distribution or sub-transmission systems and/or within a substation and have a required construction start date within the next three to five years. This timeframe is used for two different reasons. First, project design, siting, and equipment purchase takes 3-5 years to complete. Second, it can take three or more years to develop, evaluate and implement non-wires alternatives.

This procedure does not apply to projects being justified based on condition replacement or reliability benefit only. It also does not apply to customer-requested projects such as DG interconnections, line relocations to accommodate customer requests, and the installation of new developments. However, this procedure does apply to loading and/or voltage driven projects that are required due to customer requested projects.

The Company has successfully implemented one non-wires project. In 2021, the Company installed an energy storage and management system at its substation in Townsend, Massachusetts to help maximize the efficiency of renewable energy and lower costs in the region. It took approximately two years to design and install the lithium batteries and operating system, which fill one tractor-trailer sized and another smaller container. The Battery Project was designed to use the energy stored at the substation in Townsend to reduce load during key hours of the day. The battery also enabled the Company, and by extension the community, to avoid the need for future expensive upgrades at the substation level. This first of its kind project for the Company demonstrated the Company's dedication to its customers and the environment by advancing the Commonwealth's critical environmental and energy goals. The Battery Project was designed, in part, to align with Massachusetts' goal of installing energy storage systems throughout the electric grid in the Commonwealth. The project is supported by a grant from the Massachusetts Clean Energy Council.

The batteries can power up to 1,300 homes for two hours, which represents two percent of the Company's electric needs for the entire service territory in the state. Customers benefit from the Battery Project because it manages the electricity with real-time adjustments to both voltage and direction in order to maximize the efficiency of renewable energy in the region. Meanwhile, the battery in the substation is charged and ready to deploy its load at peak usage times, which is designed to lower electric costs for the Company's customers. By taking advantage of advanced software, storage capacity and the renewable energy from homeowners and businesses, the Company's Battery Project helps customers save effortlessly, which is a cornerstone in the Company's vision of a smarter energy future.

The Company will continue to manage and maximize the benefits of the EE program. Targeted spending and properly designed demand response programs may be effective to der system improvements in the future. Time varying rate structure facilitated by the AMI system will enable innovative rate designs that enable customer to manage either own usage and incentive a shift in demand away from system peaks.

The Company will continue to implement the procedure for reviewing non-wires alternatives for projects that exceed the thresholds using the process shown below:

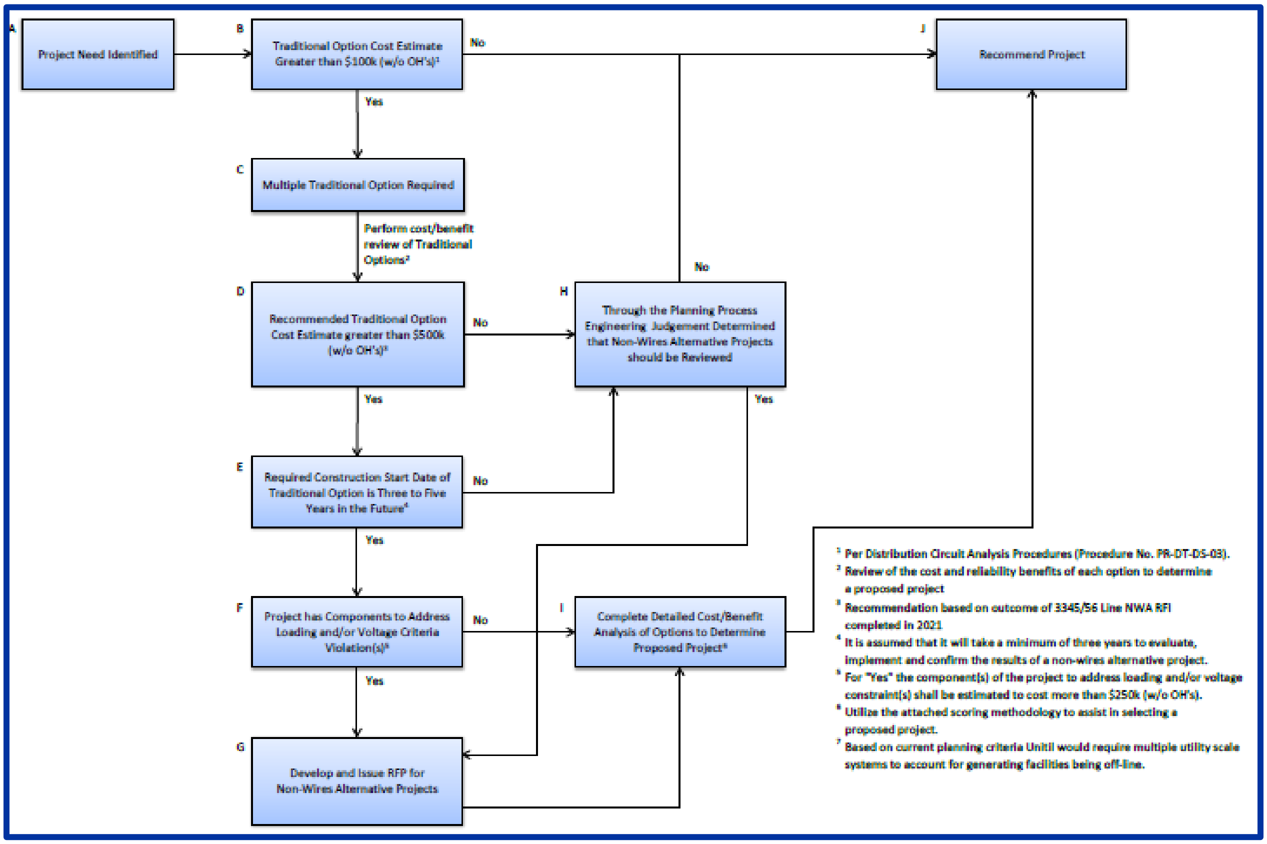

Figure 56 – NWA Project Evaluation Procedure

9.4 SYSTEM OPTIMIZATION – IMPACTS ON ELECTRIFICATION DEMAND

As explained above, the load forecast presented in this Plan shows distribution system loads increasing by 3 to 4 times by 2050. Advanced system planning tools will integrate the benefits of distributed energy resources and identify locations where these assets can be optimized. Unitil is investing in tools, including (but not limited to) DERMS, AMI, ADMS, and VVO, that will enable the Company to actively optimize the distribution system as well as provide customers the information and incentives to control and optimize their energy usage. For example, ADMS will provide the visibility and control required to operate the advanced grid in a safe and reliable manner; DERMS functionality can be used to control and optimize small localized segments of the electric system or entire feeders at a time. AMI will provide timely and accurate data to support various system, customer, and market facing technologies, as well as grid facing functions such as distribution management, system planning, and system optimization. Unitil will continue to implement and build upon these foundational investments to enhance system optimization and ensure a safe and resilient system that is prepared to meet the demands of increased DER and electrification.

9.5 ALTERNATIVE COST-ALLOCATION AND FINANCING SCENARIOS – IMPACT ON INVESTMENTS

As explained previously, the quantity and size of the DER interconnections on the Company's distribution system have not, at this time, driven the need for group studies or the implementation of a CIP project funding framework.

In the future, should the Company find the need to conduct a group study that results in significant capital investment, the Company proposes to apply the CIP approach approved by the Department in in D.P.U. 20-75-B. Any new CIP proposal would be evaluated on a case-by-case basis and submitted to the Department for review and approval.

Federal and state funding opportunities may also become available as an alternative means to fund investment. The US Department of Energy has made funding available through the Infrastructure Investment and Jobs Act. This is also more commonly known as the Bipartisan Infrastructure Law. The Company was unsuccessful in the full application submitted for the AMI project. As described above, the Company was successful in a grant award from the MassCEC for our Townsend Substation Battery project. The Company will continue to review federal and state funding opportunities as an alternative funding source for project.

9.6 ENABLING THE JUST TRANSITION THROUGH POLICY, TECHNOLOGY, AND INFRASTRUCTURE INNOVATION

Unitil's Massachusetts service territory has a significant proportion of low-income households, and a high concentration of EJ communities. In particular, the Massachusetts Executive Office of Environmental Affairs has designated 90.9 percent of the Block Groups within the City of Fitchburg as EJ communities, and approximately 86.3 percent of the total population within the

City reside within an EJ Block.[47] Approximately 65 percent of Unitil's Massachusetts customers are located within the City of Fitchburg, and as such Unitil's ESMP investments will be largely concentrated in designated EJ communities. As explained throughout this Plan, the Company will work with communities in its service territory in a transparent and engaged manner to ensure that EJ communities receive the full technological and environmental benefits of the Plan.

9.6.1 Aggregation of all clean technology incentives (in respective scenarios) focused on EJ communities

The Company attempts to design projects and programs that all customers can participate in. As explained above, Unitil's ESMP investments will be largely concentrated in designated EJ communities. The Company will engage with EJ communities on rate offerings, EE programs and to educate them on electric sector modernization.

9.6.2 Discussion of potential to use incentives and dis-incentives to align with distribution upgrades

The Company designs rates that reflect the costs and usage characteristics of each rate class as they have changed over time, and considers precedents and procedures established by the Department. In designing rates, the Company applies core rate design principles while incorporating public policy directives such as EV TOU rates.

The average long-run cost to customers can be expected to be mitigated to some extent due to the increased sales volumes that will come with electrification. Making thoughtful decisions around rate design and cost allocation will be critical to ensuring a just transition so that certain customers or classes of customers are not unduly burdened by higher system costs.

Distribution rates refer to the prices charged by EDCs for delivering electricity to end-use consumers through their distribution networks. These rates recover the costs associated with maintaining and operating the distribution infrastructure, including power lines, transformers, substations, and other equipment necessary to ensure reliable delivery of electricity. Additionally, rates for distribution service include the costs of providing customer, administrative and related services for which the EDC is responsible.

[47] https://s3.us-east-1.amazonaws.com/download.massgis.digital.mass.gov/shapefiles/census2020/EJ%202020%20updated%20municipal%20statistics%20Nov%202022.pdf

Distribution rates consist of three key design components:

1. Fixed Charges: These rates are a flat fee charged to customers regardless of their electricity usage. Fixed charges typically cover the utility's fixed customer costs, such as customer service, meter and meter reading and administrative expenses. This type of charge reflects costs that do not scale with load.

2. Demand Charges: Demand charges are calculated on the amount of capacity used by a customer over a specific time interval, usually measured in kilowatts (kW). These charges reflect the cost of providing capacity to meet the highest demand levels and help incentivize customers to manage their peak electricity usage efficiently.

3. Volumetric Charges: Volumetric charges are calculated on the amount of electricity consumed by customers and are measured in kilowatt-hours (kWh). A volumetric rate design is typically associated with the cost of supplied energy. Energy supply is procured by the utility from a supplier and ultimately reflects the commodity pricing in wholesale markets. Volumetric charges exist in distribution rates as a legacy of unbundling in order to maintain price continuity. They are also used to balance the impact of demand charges based on customer load profiles. Volumetric rates encourage customers to reduce their total usage, but do not incentivize customers to manage their demand.

The revenue requirement recovered by the Company must be approved by the Department along with pricing designed to collect the Company's approved cost of service. The cost of service or revenue requirement represents the revenue required to pay all operating and capital costs, including a return on investment, depreciation expense, and income and property tax expense.

Rate Design

As discussed in this ESMP, the electric power system is at an important transitional stage where customer usage, the growth of distributed energy resources, environmental goals, and economic concerns are converging to create a complex environment for public policy, the Company, and the customer. Within this context, rates can serve to help achieve a common goal (i.e. a safe and reliable electric power system that can deliver clean energy). However, it is only one tool in a strategy that includes distributed resources, energy efficiency, and efficient investment in the distribution system.

Electrification of the home and business and the increased demand for electric vehicles means that more electric energy will be required than ever before. The Company is taking steps to invest in its distribution system to accommodate this load and the renewable resources that will be introduced in support of the system. Continued load growth and investment must be managed to ensure that customers do not face an exponential growth in the cost to serve them. Cost control is inherent in the regulatory process as all investments made by the Company cannot be recovered unless they are approved by the Department of Public Utilities and deemed to be just and reasonable. In reviewing and approving rates, the Department has long adhered to commonly accepted ratemaking principles.[48] These are 1) efficiency, 2) simplicity, 3) continuity, 4) fairness, and 5) revenue stability. These five principles remain sound and should continue to be relied on in the evaluation of future rate proposals.

1. <u>Efficiency</u> means that the rate structure should allow a company to recover the cost of providing the service and should provide an accurate basis for consumers' decisions about how to best fulfill their needs. This means that the rate should allow for the collection of the Company's revenue requirement. A strict interpretation would mean that rates should not be discounted or reflect anything more or less than the cost to serve. A rate that reflects the actual embedded cost to serve informs the customer of the cost incurred by the EDC to serve them. A lower rate would send an improper price signal and potentially guide the customer into exerting a greater demand on the system than what is reflected in rates. A higher rate would potentially have the reverse effect and also send an improper price signal. In a future, where electric demand is expected to grow significantly, it becomes ever more important to convey the actual cost of the system to the customer.

   From the EDC perspective demand charges reflect the most efficient form of rate design. The primary function of the EDC is to operate and maintain system infrastructure. This infrastructure is predicated on the capacity required by its customers and independent of the volume of electricity that flows through the electric grid. For this reason, demand charges are most efficient because customers are charged based on their demand at a point in time. Volumetric charges, on the other hand, are inefficient because the electric grid needs to meet the highest demand at any point in time and not the aggregate volume over a specified duration. Given the increasing demand among customers due to various installations ranging from modern appliances to electric vehicles, the Company believes that demand charges, time varying rates (TVR) and fixed charges should be given greater consideration in the evaluation of future base distribution rate proposals.

[48] Espoused by James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen in Principles of Public Utility Rates

2. Simplicity means that the rate structure should be easily understood; thereby enabling consumers to make appropriate decisions about use. The simplest electric rate design today is a two-part rate consisting of a customer charge and an energy charge. This is the type of design that residential customers and small C&I customers see today. Customers can easily understand a fixed charge and that volume of consumption can increase or decrease their bill. Simplicity, however, has become a challenging concept today when there is a demand for increasing amounts of data. The deployment of AMI meters enables the potential for more data to be made available to customers in addition to more complex rate designs such as time-of-use variants. However, the Company believes that complex rate designs should be considered carefully. Information can be misunderstood if customers are not educated about the subject or do not have the time and resources to analyze complex data sets. It is important to understand that customers are diverse. For example, the development of the competitive energy supply market offers instructive lessons. The introduction of retail energy suppliers has given customers options and larger customers, in particular, can negotiate contracts and obtain optimal pricing for their needs. Such customers, however, may have staff devoted to analysis of energy costs and needs. An individual residential customer, on the other hand, does not have such resources or bargaining power. Many do not fully understand energy markets and are vulnerable to exploitation by unscrupulous parties.

3. Continuity means that rate changes should be made in a predictable and gradual manner that allows customers reasonable time to adjust their consumption patterns in response to a change in structure. The continuity principle means that radical changes cannot be introduced at one time because it inevitably results in adverse bill impacts to one customer or another. Changing time-of-use periods is an example of a potential change that could significantly impact customers. Some may immediately gain advantage while others may see the opposite. For instance, changing a peak period from 9 am to 6 pm to 4 pm to 9 pm could have a material impact on certain customers. A small business that closes shop at 4 pm would benefit significantly without any change in behavior. Meanwhile, a restaurant could see a negative impact because the change would fall within its prime dinner service. Often times, new rate designs are introduced as options to smooth customer transitions. Optional rates mean that customers will self-select which can assist in the formation of a rate class. Optional rates, however, also mean that the rate design may not change behavior because customers that do not see an immediate advantage are unlikely to elect the rate.

4. Fairness means that no class of consumers should pay more than the costs of serving that rate class. This principle seeks to limit the amount of cross-subsidization across rate

classes or customers within a rate class. Additionally, rate design choices can have meaningful impacts on public policy goals and customer adoption of clean energy technologies.

As clean energy markets mature and adoption rates grow significantly in furtherance of state goals, rate designs that are mindful of the continued need for EDCs to equitably recover their fixed costs from customers will be increasingly critical. This may mean future transitions away from purely volumetric rates to more sophisticated rate structures that preserve contributions from all customers that take service from an EDC. Customer charges and demand-related charges are potential mechanisms for achieving this outcome. Transitioning cost recovery away from high volumetric charges could have an added benefit of improving the economics of electrification where volumetric usage may be higher. Any change to rate designs requires thoughtful consideration, particularly related to impacts on low-income customers that may be disproportionally impacted by fixed charges or who may have limited opportunities to avoid demand charges. Given this, any rate reform should holistically consider how the Commonwealth's existing low-income discounts mitigate these unintended impacts.

5. Revenue stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. Revenue stability leads to stable rates. If rates are unable to collect the costs incurred by the Company, more frequent rate changes will be required. In recent years, some parties have argued for pricing based purely on marginal cost. The arguments supporting this are often confused because they do not reconcile marginal costs with embedded costs. Marginal costs represent the cost of making a future investment while embedded costs represent the costs that have already been incurred. The former represents a price signal to customers about the implications of their future load while the latter represents the actual cost to serve. Rates are a blend of both. They need to send appropriate price signals yet recover the total cost to serve. Pricing purely at marginal cost would leave the Company under-recovered and ultimately result in increased rates for all other customers. In order to manage costs for all customers, the total cost of the distribution system needs to be shared among its users.

The long-standing rate principles of efficiency, simplicity, continuity, fairness, and earnings stability need to be weighed against each other and cannot be viewed in isolation. Often times, one principle may be prioritized over another in order to achieve an outcome that meets the real world needs of customers, policymakers, and the EDCs. The Company believes that emphasis should be given to efficiency and cost responsibility in the years ahead. Maintaining cost responsibility will help reinforce fairness and stability and allow for continued investment in the electric power system in order to meet future system demands. In this fashion, there can be continued investment in the distribution system without a significant impact on customers over the long run.

9.6.3 Potential incentive allocation movement among clean technologies ultimately flowing toward disadvantaged communities

The Company recognizes that populations in EJ and other communities may face barriers to participation in programs that help customers manage bills or provide new opportunities for customer participation in the clean energy transition. The Company will continue to identify opportunities for outreach and support to low- to moderate-income ("LMI") customers.

The Company currently offers a number of programs to assist low-income customers. This includes a 34.5 percent discount on the total bill for residential customers taking service under Rate R-2. In August 2023, Unitil filed a proposal in D.P.U. 23-80, its base rate proceeding, to increase the discount from 34.5 percent to 40 percent. Eligibility for the low-income rate discount is subject to verification of any means-tested public benefit, eligibility for the low-income home energy assistance program (or its successor program) for which eligibility does not exceed 60.00 percent of state-wide median household income, or other criteria approved by the Department. The Company also offers a budget billing option that allows customers to allocate payments across 12-months to make bills more predictable and facilitate cost management.

The Company's affiliate in New Hampshire, Unitil Energy Systems, Inc., participates in the Low-Income Electric Assistance Program, which is a statewide program that provides discounts on customers' total bills. That program includes five tiers tied to the federal poverty level and discounts ranging from eight percent to seventy-six percent. The program, which is operated by the state's electric utilities in conjunction with the Community Action Agencies, the Office of Energy and Planning, and the Department of Energy, targets the neediest households based on Federal Poverty Guidelines ("FPG"). The discounts decline gradually, beginning with customers in the lowest FPG group such that the lowest discount applies to customers in the highest FPG group. The current program design goal is to make electricity affordable at approximately 4.50 percent of gross household income. As the Commonwealth advances towards electrification there may be an opportunity to revisit low-income programs on a statewide basis.

The Company does not maintain records of customer income, nor would that be appropriate. Enrollment in a discounted rate today is based on verification with the Commonwealth that a customer is enrolled in a means-tested program. Thus, the Commonwealth needs to partner with the Company in the implementation of such a program. As the Commonwealth advances towards electrification and the Company increases its infrastructure investment to meet policy goals, the opportunity to address the impacts to LMI customers is immediate.

The need for investment to achieve state climate goals also warrants discussion on how incentives that are paid to customers are recovered through rates (e.g., EE charges) or whether incentives should be managed through distribution charges. As the Company moves to an increasingly electrified system, careful consideration should be given to cost allocation and rate design principles to ensure a just transition. Moreover, it is important to note that the layering of incentives into utility rates will ultimately increase costs. Consequently, it will be important to design rates that will minimize cost shifting and not increase the cost burden for customers.

On December 6, 2023, the Department of Public Utilities issued its D.P.U. 20-80-B Order on Regulatory Principles and Framework. This Order addressed the Department's investigation into the role of gas local distribution companies in the achievement of the Commonwealth's 2050 climate goals (aka "Future of Gas"). In that Order, the Department acknowledged the potential for a growing cost burden on customers as the Commonwealth advanced its policy of electrification. Consequently, the Department plans to address these issues in a separate proceeding that will be "dedicated toward examining innovative solutions to address the energy burden and affordability, such as capping energy bills by percentage of income or offering varying levels of low-income discounts, that have been implemented in other jurisdictions" (Order at 16).

On January 4, 2024, the Department opened this separate proceeding as an inquiry to examine energy burden with a focus on energy affordability for residential customers of the EDCs (and of gas distribution companies) (D.P.U. 24-15). The Company welcomes this investigation and looks forward to a robust discussion with the Department, EDCs, and stakeholders.

A myriad of related issues emerges as the Commonwealth, EDCs, and stakeholders contemplate issues of equity and rate design, each of which should be comprehensively addressed by the Department and interested stakeholders in a longer-term process than the ESMP process allows, including:

- TVR should be considered in the context of a comprehensive policy in consideration of solar and storage. Efforts at altering customer behavior should not be viewed in isolation as the impact to the electric power system is the result of the sum total of customer actions.

- The Company filed an electric vehicle specific time-of-use in D.P.U. 21-92. Targeted TVR rate design is a granular approach that will offer bill savings to selected participants.

- The Company has been actively participating in an AMI stakeholder process ordered under D.P.U. 21-82-B. The Order directed the stakeholder process to focus on 1) customer and third-party access to customer usage data; 2) customer education and engagement; 3) billing of TVR offered by competitive suppliers; and 4) AMI deployment strategies that may expedite the ability for competitive suppliers to offer TVR products. Issues of supplier TVR rates have an impact on any future TVR basic service proposal. Municipal aggregations and competitive suppliers have taken a significant hold in the Company's territory. As of December 2023, approximately 10% of customers in the Company's territory remain on Basic Service.

- Customer Education is a pivotal component of AMI upgrade and rate design. AMI allows for the collection of more granular data among residential customers in a cost-effective fashion. Today, the Company cannot collect 15-minute or less intervals without deployment of interval meters. Collection of data will allow the Company and policymakers to better understand how customers behave across municipalities. Analysis of that information will lead to rate designs that can address different usage patterns as well as the ability to segment customers more granularly over time.

- Complex rate designs require greater communication with the customer in order to educate them on how their energy profile impacts their bill and how they can manage their costs through the tools available to them. The complexity of any rate design needs to be balanced against a customer's ability to act on price signals in an effective and efficient manner.

The Company supports transitioning to an electrified future in an equitable and just manner and supports rate designs and public policy programs that will result in a constructive path forward.

9.7 NEW TECHNOLOGY PLATFORMS

The foundation of any new technology is data. Investments in AMI infrastructure will increase the granularity and timeliness of data. Sharing that data with the customer will be important. In the 2035-2050 timeframe, the Company expects a high penetration of home energy management systems in constant communication with the utility. Customers will control their entire home from their smart phone and will need data to do so. Metering technology will continue to advance and the Company will enable this technology for our customers.

The Company is implementing customer focused tools and programs to improve customer engagement and experience. The Company is currently implementing several customer tools within grid modernization to provide the customer added control over their energy usage. The Company is committed to continuous improvement in the customer experience and will continue to improve its customer marketplace and customer portals to facilitate new tools and technology.

Cyber security will become increasingly important. The overall security of the electric system and the system that runs the electric system is a top priority. Increased data sharing and control functions may place added stress on the Company's cyber security controls and systems. The Company will continue to build upon its current cyber security program to increase the monitoring of the electric system and computer networks.

The reliability and resiliency of the system will always be a focus of the Company. Technology improvements will be implemented to reduce the frequency and duration of outages. Replacement of aging equipment with newer and more efficient equipment will ensure the system continues to be operated in a safe and reliable manner. Continued installation of targeted spacer cable, targeted undergrounding and distribution automation will also reduce the frequency and duration of outages.

10 RELIABLE AND RESILIENT DISTRIBUTION SYSTEM

10.1 REVIEW OF THE COMMONWEALTH'S CLIMATE CHANGE ASSESSMENT AND HAZARD MITIGATION AND CLIMATE ADAPTATION PLANS

In September, 2018, the Commonwealth of Massachusetts released its first State Hazard Mitigation and Climate Adaption Plan ("SHMCAP").[49] This plan, developed in response to the Governor's Executive Order 569,[50] on climate change, integrates climate change impact with strategies to address the risks associated with climate change. The Commonwealth updated the Plan (the "ResilientMass Plan") in September 2023.[51]

The plan forecasts projected changes in extreme weather events, precipitation, sea level rise and temperature and develops strategies to reduce the risks associated with climate change. Changes in precipitation can cause inland flooding, drought and landslides. Sea level rise can cause coastal flooding and erosion. Rising temperatures can cause increasing average and extreme temperatures, wildfires and invasive species. Climate change can also create more frequent and more severe hurricanes and tropical storms, severe winter storms such as nor'easters, tornadoes and other severe weather.

The risk assessment identifies the vulnerability to climate change is a function of exposure, sensitivity and adaptive capacity. The plan includes a strategy and action plan to reduce the risks associated with climate change and the improved resilience of the Commonwealth to climate change.

An Act Driving Clean Energy and Offshore Wind at Section 92B (b)(i) specifies that each ESMP include and describe in detail improvements to the electric distribution system to increase reliability and strengthen system resiliency so potential weather-related and disaster-related risks are addressed. The transition to Net Zero by 2050 and the full electrification of the Commonwealth will bring new expectations for a reliable and resilient network as customers rely

[49] https://www.mass.gov/info-details/massachusetts-integrated-state-hazard-mitigation-and-climate-adaptation-plan

[50] https://www.mass.gov/executive-orders/no-569-establishing-an-integrated-climate-change-strategy-for-the-commonwealth

[51] https://www.mass.gov/doc/resilientmass-plan-2023/download

on the Company's networks for increased electric vehicle charging and heating in addition to the many ways that they use electricity today.

Weather events, primarily storms involving wind and/or precipitation, can result in vegetation and distribution asset failures and have significant impact on the distribution system's performance. Climate change is widely understood to be contributing to an increase in frequency and severity of storm events. Additionally, increased customer reliance on electricity has led to increased expectations for the distribution system's reliable performance. Significant outage durations, even when resulting from significant weather events, are becoming untenable to many customers.

The Company has identified many of the same risks to our infrastructure as are identified in the State's plan. Increases in the severity of storms can cause more damage and increased outage duration for the electric system. Inland flooding, if severe enough, could damage equipment in substations and create travel problems for crews trying to restore outages. Rising temperature can cause electric load to increase and equipment ratings to decrease, all resulting in more frequent equipment failures. The Company goes into further description of its climate assessment review in section 10.4. As the Company further develops its climate vulnerability assessment, it will incorporate findings and align with these plans

10.2 DISTRIBUTION RELIABILITY PROGRAMS

The Company takes a comprehensive approach to reliability and resiliency planning and is as important as traditional load flow or circuit analysis planning. Reliability planning is conducted by Operations and Engineering staff on an ongoing basis. Projects and programs are designed and implemented to: 1) eliminate the outage from occurring or 2) minimize the impact of an outage by reducing the number of customers affected and/or the duration of time they are affected for. The various types of reliability planning are identified below.

Daily – Unitil Operations and Engineering personnel review every sustained outage on a daily basis. This review focuses on system improvements that could be made in order to prevent that outage from reoccurring or other resiliency measures to reduce the size or duration of the outage. Typically, this review results in protection or construction modifications or targeted out of cycle trimming activities.

Weekly – Internal reports on overall company and individual operating center reliability performance compared to annual goals and past history are developed on a weekly basis.

This review is used to track the current year reliability and resiliency performance and benchmark it against company goals and historical performance.

Monthly – On a monthly basis, the Company summarizes the significant outages – outages that account for 75,000 customer-minutes of interruption or more, that occurred in each of the operating companies over the past month. The analysis also reports on devices that have experienced multiple outages over a specific period of time and also reports on outages caused by failures of company equipment. The goal of this reporting is to identify trends and potential causes for the trends and initiate system improvements to address those trends.

System Event Report ("SER") – At the discretion of the Company's executive team any outage can have an SER report completed. An SER is a root cause analysis conducted by Operations and Engineering. The goal is to identify ways that the outage could either be avoided or the response shortened in the future. Typically, an SER recommends action items that are assigned and completed.

Annual – The Company conducts analysis on an annual basis that is focused upon the overall reliability and resilience performance of the system for a 12-month period. The reports evaluate individual circuit performance over the same time period. These reports are developed per Unitil's Reliability Analysis Guideline and include:

- Analysis of the ten worst outages that occurred over the timeframe along with their associated impact to SAIDI and SAIFI;
- Analysis of the effect of sub-transmission and substation outages on circuit performance;
- Analysis of the worst performing distribution circuits over the reporting period;
- Analysis of the major causes of sustained interruptions;
- Analysis of performance issues on specific circuits as well as recommendations for improvement;
- Analysis of equipment failures to identify trends and provide recommendations when necessary;
- Analysis of areas with multiple tree related outages for consideration for additional tree trimming; and
- Analysis of devices that have operated on more than three occasions over the timeframe.

Reliability improvement projects are designed and estimated. Each of the projects is compared based upon a cost per saved customer-minute and a saved customer-interruption basis. These projects are submitted for capital budget consideration. The funding level for projects strictly justified on reliability improvement is approximately $1 million. Typical projects include: addition of reclosers or sectionalizers to decrease the outage zone, targeted spacer cable, circuit ties, and automation schemes to isolate and restore load. The reliability planning process described above has proven very successful. The historical reliability performance for the system is outlined below.

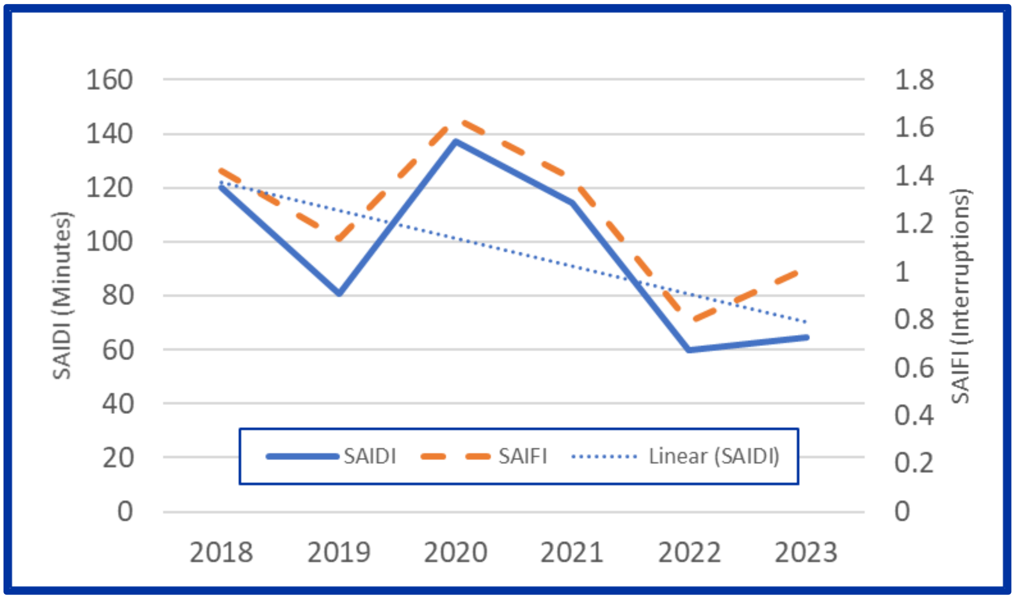

Figure 57 – Reliability Performance

The chart above, displays annual SAIDI and SAIFI using Department exclusionary criteria. The 2022 reliability performance was the best performance in over 25 years. The 2023 system SAIDI of 64.6 minutes is roughly 25 percent lower than the 10-year average of 86.1 minutes. The system SAIFI for 2022 was 0.79 interruptions which was the best performance in over 25 years. The system 2023 SAIFI of 1.016 interruptions is approximately 17 percent lower than the 10-year average of 1.22 interruptions.

The Company also has charted circuit reliability in relation to the percent of customer served by that circuit living in an EJC. The figure below identifies there is no statistical correlation between reliability and percent of customers on the circuit served living in an EJC.

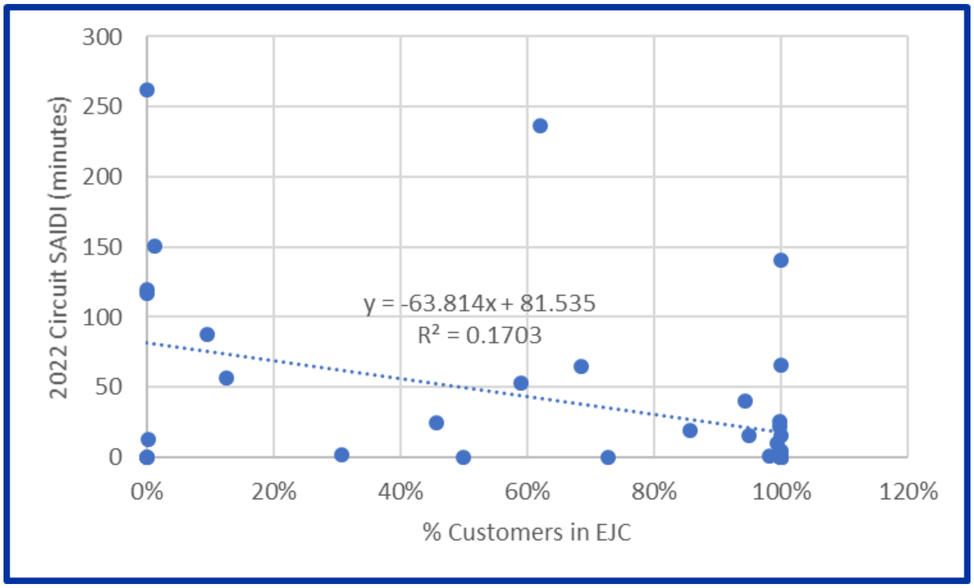

Figure 58 – 2022 Circuit Reliability by Percent of EJC Customers Served

The Company's vegetation management program (including its cycle pruning and Storm Resiliency Program described in the following section) has a large impact on the reliability performance of the company. The Company is experiencing improved performance during both blue sky as well as major outage situations. The vegetation management program is resulting in less damage during storms allowing the Company to consistently complete restoration ahead of neighboring utilities and send line resources to assist others with restoration. The Company continues to evaluate the program for improvements where practical.

Distribution and Sub-transmission Pole Replacements

In order to ensure the safe operation of the electric distribution system, regular inspections of the distribution and sub-transmission poles must be made to ensure a strong and resilient pole plant. On a ten-year cycle, wood distribution poles in the DOC's maintenance area shall be visually inspected and tested at and below grade level to determine the soundness of the wood. The initial inspection of poles shall take place at or before the pole age of twenty (20) years.

Two of the most destructive forces affecting wooden poles is decay and loss of cavity. These will generally progress at a predictable rate and the advancement of decay can be readily diagnosed in the field at all but the very early stages. Detection of decay, loss of cavity, or damage is essential in establishing the remaining pole life.

Unitil utilizes a resistograph to perform pole testing. The resistograph, is a non-destructive test device that determines the decay and cavity degree of the poly by capturing the resistance of the constant force of a special micro-drill bit as it travels through the wood of the pole. This allows the user to identify soft spots and voids inside the wood. A corresponding graph is produced that shows the depth (inches and cm) and changes in density according to resistance providing a profile of the pole. Data from this device is utilized in various computer models to determine the strength of the pole.

Currently, an electronic field mobile tablet is utilized in conjunction with web-based software to record and retrieve information for the majority of the aforementioned inspections. This software links directly to the Company's internal record data bases. The results of all cycle inspections and tests and corrective actions taken are recorded and retained for one complete cycle but not less than a period of six years. Inspection reports identify all poles/equipment inspected. All non-compliant findings are noted indicating corrective action to be taken and close out date (i.e., when corrective action was completed). Poles are prioritized for replacement based the resistograph and visual inspections.

Emergency Response Plan

Even the most successful reliability and resiliency program will not eliminate all outages. The Company's Emergency Response Plan is designed to be a guide for the activation of the Electric Emergency Response Organization. Its purpose is to ensure the effective implementation and coordination of the corporate emergency response actions during an Emergency Event. The ERP utilizes the National Incident Management System which is a comprehensive national approach to incident management applicable at all jurisdictional levels and across functional disciplines.

The ERP also addresses the operation of the Emergency Operations Centers. The plan remains focused on public safety, workforce safety and safety of outside aid and is designed for the reasonably prompt restoration of service during an Electrical Emergency Event.

The ERP addresses electric emergency response to customer outages caused by weather (e.g. thunderstorms, hurricanes, tornadoes, extreme heat, storm surge, river flooding) other natural or man-made causes (e.g., major equipment failure, civil unrest, terrorism, wildfire, etc.), or disasters causing significant customer interruptions and is predicated on knowing and understanding the magnitude of the event. The ERP is in accordance with all applicable regulations and is designed under the Incident Command System and Unitil's Crisis Response Plan.

10.3 DISTRIBUTION RESILIENCY HARDENING PROGRAMS

Comprehensive Vegetation Management Program

The tree density in the Company's service territory is in the upper quartile of tree densities (137 trees per mile) when compared to other utilities throughout the United States, which is an average 96 trees per mile. The Company has experienced a decline in forest health and the trees within its service territory. Trees in Massachusetts have been subjected to several environmental stressors in recent years, including the emerald ash borer, spongy (formerly gypsy) moths and white pine needlecast, which can lead to increased tree/limb fall during both blue sky days and severe weather events.

Given the environmental stressors and weather events and the impact they have had on the tree population in Massachusetts, the Company has long been focused on vegetation management activities to address those impacts. As part of its mandate to provide safe and reliable service to its customers, the Company has consistently taken proactive steps to enhance and protect its distribution system from vegetation impacts using a two-pronged approach: its annual vegetation management activities and the Storm Resiliency Program ("SRP"). These programs are critical given that the Company's system infrastructure is unavoidably exposed to many different weather events, like ice storms and heavy wet snow, such as the January 2023 winter storm, that can cause substantial damage and prolonged power interruptions. To combat this, the Company relies on a comprehensive vegetation management program that is designed to prevent trees from interfering with electric lines during normal weather conditions and minor storm events. The program's components cost-effectively address the different areas of risk and provide benefits to customers, support favorable reliability, and provide a measure of public safety. The Company has made several modifications to the vegetation management program in recent years to optimize the benefits of the program while ensuring that the Company retains the necessary flexibility to direct the program in a manner that benefits customers.

Additionally, the Company has, since 2014, utilized the SRP to mitigate and eliminate system-level severe weather event vegetation risks that could otherwise negatively impact the system, and customers, during these events. Under the SRP, the Company has made significant progress in reducing tree exposure along electric overhead lines in order to reduce the overall cost of storm preparation and response and improve system resiliency during major storm events.

The Company's comprehensive vegetation management program consists of three main components: cycle pruning; hazard tree mitigation; and forestry reliability assessment. Each component of the program is designed to minimize the potential for tree and vegetation contact with the overhead utility lines and the incidence and resulting damage of tree and limb failures from above and alongside the conductors.

Vegetation maintenance pruning and clearing done on a cyclical schedule by circuit is called "cycle pruning". The Company's base cycle length is five years. The Company has recently transitioned from a four-year cycle to a five-year cycle based on the need to focus efforts and resources on increased hazard tree removals. This decision was driven, in large part, by the decline in forest health and increase in tree mortality. The move to a five-year cycle allowed for resources to become available to undertake a cycle pruning mid-cycle assessment, to identify and address any emergent vegetation issues, and perform additional hazard tree removal. Under these mid-cycle assessments, the Company visually inspects every transmission and distribution line at least every three years to ensure that no areas of the distribution system are left unattended. If the Company encounters any vegetation issues while conducting the mid-cycle assessments, such as hazard trees that warrant removal to avoid impacts to the system, the Company addresses the issue in the near term, rather than waiting until the start of the next five-year cycle. By undertaking these mid-cycle assessments, the Company proactively addresses potential vegetation issues cost-effectively.

The vegetation management program has a non-discretionary or "Core Work" component. This critical component of the vegetation management program enables the Company to respond to emergencies, customer requests, new construction needs, and other non-discretionary and unscheduled work. A dedicated number of specialized crews are required on site on a year-round basis to address the Company's Core Work needs.

A hazard tree is a danger tree (any tree which, on failure, is capable of interfering with the safe, reliable distribution of electricity) that has both a target and a noticeable defect that increases the likelihood of failure. The hazard tree mitigation component program involves the consolidation of hazard tree removal activities into a formalized program to drive both operational and cost efficiencies. As noted above, hazard trees can be identified during the five-year pruning cycle or as part of the mid-cycle assessments. Additionally, the Company can identify, based on field conditions including incidents of past tree failure and/or poor performing circuits ("PPC"), targeted hazard tree mitigation assessments where a more intensive hazard tree inspection is necessary. These assessments include a more detailed visual tree assessment and a wider scope of assessed trees. This more intensive inspection generally leads to an increased number of hazard trees to be removed per mile. No matter the how the hazard trees are identified, the Company takes the same steps to prioritize, and efficiently and effectively remove these trees before they can impact the system and customers.

The forestry reliability assessment program component targets circuits for inspection, pruning, and hazard tree removal based on recent historic reliability performance. Identifying and addressing PPC or circuits that could become PPC in this manner gives the Company the flexibility to quickly react to and address immediate reliability issues, rather than waiting for the circuit to be addressed as part of mid-cycle or the five-year maintenance cycle.

The Company has designed the integrated components of the vegetation management program to meet the Commonwealth's regulatory targets and expectations and increase customer satisfaction through improved reliability performance. In addition to these overall goals, cycle pruning also provides a measure of public safety by minimizing the potential for public direct contact with downed wires as a result of failing trees and limbs, with energized conductors by climbing trees and indirect contact though vegetation in contact with energized equipment, as well as minimizing the potential for electrically caused fire in trees and brush.

The Company has a sub-transmission maintenance component that applies the principles and practices of integrated vegetation management ("IVM") to maintain the rights-of-way. This includes identifying compatible and incompatible vegetation, considering action thresholds, evaluating control methods and selecting and implementing controls to achieve a specific objective. The plants to be controlled are primarily tall growing trees that can grow into or fall onto electric lines. Right-of-way maintenance includes cyclical floor maintenance, such as mowing, hand cutting, and herbicide application; sideline pruning; and hazard tree removal.

The Company has developed a vegetation management contract strategy to strive for the lowest market price and minimize the program components' costs where possible. This was done by first outlining the vegetation management goals and strategies for delivering work and minimizing risk and associated cost, and then by listing the contract methods and types available for award of work to qualified line-clearance vendors. The strategy multiple vendor Lump Sum Fixed Price Bid, Unit Price Bid award, as well as single vendor three-year contract "time and material" award. The Company carefully balances the benefits of a longer-term contract with the need to respond to market pricing to attract and retain skilled workers.

The Company has also implemented an evaluation program that tracks vendors' work and progress, including progress in meeting Company expectations and key indicators. Their performance is one of the factors considered when the Company is procuring services. Utilizing this performance evaluation program as an indicator of future work assists in workforce retention while ensuring that customers are benefitting from high quality, consistent work that enables the Company to continue to provide safe and reliable service.

Storm Resiliency Program

The increase in significant, severe weather events impacting the service territory and the Company's customers was the main impetus behind the introduction of the SRP. In 2011, the Company was impacted by two significant weather events that affected the Company's service territory, Hurricane Irene and the October Snowstorm, where over two feet of snowfall was recorded in Massachusetts. The 2011 October Snowstorm caused widespread damage and prolonged outages and was the second largest event in the Company's history. In 2012, Hurricane Sandy impacted the Company's service territory and customers. Prior to 2011, the Company's system had also sustained damage due to other frequently occurring storm events. In addition, there are comprehensive and stringent statutory and regulatory requirements for all distribution companies in the Commonwealth that increase the standards and obligations for storm preparedness and response.

In the interest of customers, the Company recognized the need to proactively address the situation and began to explore the options available to "harden" or make critical elements of the system more resilient to storms. After the review of different options available, such as undergrounding electric lines, and reviewing rough cost estimates, the Company recognized that there was an opportunity to implement a vegetation-centered storm hardening program that would provide customer benefits at a lower cost than other alternatives.

The SRP differs from the vegetation management program in that it is designed to reduce tree exposure along select circuits in order to improve performance during major storm events. The goal of this program is to reduce tree-related incidents and the resulting customer interruptions, as well as impacts to municipalities, including identified critical facilities such as hospitals and police and fire stations, along critical portions of targeted lines in minor and major weather events. In turn, the Company has implemented the SRP in a manner designed to reduce the overall cost of storm preparation and response, improve restoration, and preserve municipal critical infrastructure for the purpose of enhancing public health and safety.

Under the SRP, critical three-phase sections of select circuits, defined as the circuitry from the substation out to a desired protection device, undergo tree exposure reduction by: (i) removing all overhanging vegetation, or pruning “ground to sky;” and (ii) performing intensive hazard tree review and removal. In addition, under the SRP the remaining three-phase circuitry beyond the designated critical portions undergoes hazard tree review and removal. In selecting the portions of circuits to include in the SRP, the Company takes into account the critical infrastructure needs of the towns and cities served by the circuits. The locations of police and fire departments, schools, emergency shelters and other critical business centers are therefore considered along with the critical electric infrastructure when selecting the circuits.

Based on recent analysis, the SRP is providing definite reliability benefits to customers and there is a clear improvement trend in SRP circuit performance for SAIDI, SAIFI, and CAIDI as compared to the non-SRP circuit performance. Specifically, under storm conditions, the SRP circuits substantially outperformed the Non-SRP circuits. Given the benefits to customers, it is critical that the Company continue to implement the SRP to avoid a loss of those benefits.

The SRP was designed to prevent tree-related failures and attendant customer outages by implementing the comprehensive activities described above, which would in turn improve reliability, improve customer service and satisfaction, reduce safety risks, and avoid preparation and restoration costs during storm events. In developing the SRP, the Company also determined that there were additional benefits that were expected to materialize, including:

- Preserving municipal critical infrastructure;
- Minimizing the dependence on mutual aid and off system resources;
- Minimizing the total number of resources required to restore service;
- Shortening the duration of major events;
- Minimizing the overall cost of restoration;
- Reducing economic loss to municipals, businesses, and customers; and
- Most cost-effective solution versus other alternatives.

The Company consciously selected SRP work areas that included much of a municipality’s critical infrastructure. These areas are also most often the business centers for the municipality, and therefore include gas stations, restaurants and hotels. Preserving power during multiple-day weather events to both municipal infrastructure and business districts ensures that emergency services have power and are able to function and residents have options for seeking temporary warmth and shelter.

In addition, as many states and regulatory jurisdictions have established standards for restoring power during major events, the competition for securing outside line resources has increased significantly and, as a result, resources have become both scarce and very expensive. Often, in order to secure an adequate amount of resources for a particular event, the Company has been required to reach outside of New England, adding travel time and additional cost. The SRP helps avoid these increased costs by preventing the damage from occurring in the first place. If there is less damage to the system due to fewer tree/limb falls, there will be a reduced need for outside crews, which, in turn, lowers overall storm restoration costs and shortens the duration of an event.

The Company, based on its interactions with the municipalities and businesses it serves, recognizes the significant economic impact of losing power for multiple days. These natural disasters are very disruptive, result in a loss of business income and tax revenue, personal income loss, and increased costs to municipalities due to the requirements of providing emergency services, debris removal, and requiring overtime work for multiple departments. Since the Company designed the SRP to reduce tree/limb falls that impact the system, these municipalities and businesses will benefit from a reduced number/duration of outages.

Similarly, residential customers have expressed concern with losing power for multiple days. Although it is impossible to prevent storm damage across the entire system, the SRP's focus on preserving power and minimizing damage for each municipality along its main business corridor, as well as protecting its emergency critical infrastructure, provides residential customers with a measure of security during and after these extreme weather events. Additionally, since the SRP is designed to mitigate the impact of vegetation on identified circuits, residential customers would benefit from fewer/shorter outages.

Lastly, when the Company initially began looking at ways to harden the system against the impacts of major weather events, it did consider different options, such as undergrounding electric lines. Given the significant costs associated with undergrounding distribution circuits, the SRP presented a highly effective and cost-effective method of reducing both the frequency and duration of outages.

Since implementing this program, the Company has identified a reduction in the duration of major events and a reduction in overall cost of the events, due to reduction in damage and resources required to restore service. In the early years of the SRP, the Company compared storms that had recently impacted the service territory with pre-SRP storms with similar forecasts and resulting weather to identify if the expected benefits of the SRP were being realized. While the nature, variability and complexity of storms made comparing storms a challenge, the Company did determine that there had been a reduction in damage between similar storms. For example, both the wind event of March 2, 2017 and the wind event of January 4, 2018, had sustained winds reaching 35mph and wind gusts reaching 55mph. However, the circuits that underwent SRP work in October 2017, in the time between these two storms, fared significantly better in the January 2018 storm, after the SRP work was done. The March 2017 storm resulted in 18 tree-related outages while the January 2018 storm resulted in one tree- related outage.

The Company has also determined that the reduction in damage has translated to overall event time restoration. In comparing relatively similar storms Hurricane Sandy in 2012 (pre-SRP) and the post-SRP implementation March 2017 Wind Event, and January 4, 2018 wind storm, restoration time was improved by over 24 hours, with less than half the number of crews needed to restore service. For winter storms, the results were similar. In comparing the November 26, 2014 winter storm Cato, which had 12 inches of wet snow, to the two 2023 winter storms Kassandra (January 23, 2023 - 15 inches of wet snow) and Sage (March 14, 2023 – 30 inches of wet snow) there was a 61% improvement and a 55% improvement, respectively in numbers of customers impacted plus an improvement in restoration time by 24 hours. Please see Exhibit Unitil-SMS-6 for a graphical depiction of Unitil historical restorations and a reduction in storm duration.

More recent analysis, focused on a review of outages pre- and post-SRP completion, has demonstrated that the benefits associated with SRP continue to accrue to customers. Circuits that are included in the SRP had far lower CMI per event ratios than non-SRP circuits.
A reduction in total storm costs typically has gone hand in hand with reduction of overall storm event duration. Although each storm is unique, as is the preparation for and response to the storm, the Company's analysis has determined a reduction in storm cost of $397,000 for the March 2017 storm to $25,000 for the January 2018 storm. After completing restoration on its system, the Company has also been able to provide mutual aid support by releasing additional contractors, and sending its own internal resources to assist other utilities in their restoration efforts. This has occurred on at least 11 occasions since 2019.

Distribution Circuit Ties and Automation

The ability to switch load between different sources provides a level of flexibility for day to day as well as improves reliability and resiliency during outage conditions. The Company conducts a master plan review as part of the distribution planning process. The purpose of the master plan is to provide strategic direction for the development of the electric distribution system as a whole. It does not, in and of itself, represent a cost-benefit justification for major system investments. Instead, it is intended to guide design decisions for various individual projects incrementally towards broader system objectives. The concepts detailed in the analysis are considered in all future designs of the system. It is expected that this Master Plan will be modified, adjusted, and refined as system challenges and opportunities evolve.

The master plan is used to identify the future location of circuit ties to provide the ability to switch load between substations and improve the overall reliability and resiliency of the system. The reliability and resiliency plan reviews locations where new circuit ties and automated restoration schemes would have reduced the overall size and impact of outages. Projects are evaluated and prioritized based upon 1) project cost per saved customer minute and 2) project cost per saved customer interruption.

Spacer Cable

As described above, the Company's service territory has above average tree density. The Company uses a comprehensive approach to vegetation management and SRP to address this challenge. However, the vegetation management and SRP programs rely on customer and town approvals to trim and remove trees.

The Scenic Road Act,[52] a state statue designed to protect trees and stone walls within the road right-of-way for streets that have been designated as "Scenic Roads", has been adopted by the cities and towns within our service territory. The Scenic Road Act requires that a public hearing before the local planning board is held prior to removing a tree or altering a stone wall. The Company has worked diligently with the towns to try to obtain approval to conduct vegetation management activities along scenic roads. However, the towns generally deny these requests and the Company is left to find other means.

The vegetation management program also relies on individual customer approvals prior to conducting vegetation management activities along a given street (i.e. non-scenic roadway). Most customers are generally receptive to allowing the Company to trim and remove trees, but some are not. The Company is left to find other means when the customer does not allow trimming activities to happen.

Spacer Cable consists of overhead wire which is covered with a tree-resistant coating and oriented in a compact diamond configuration to minimize the opportunity for trees to come in contact with or get caught on the overhead lines. This is a more expensive material than bare

[52] https://malegislature.gov/Laws/GeneralLaws/PartI/TitleVII/Chapter40/Section15C

overhead conductors. Spacer cable will allow intermittent tree contact without causing an outage. Spacer cable is an excellent option where trimming rights are not granted and the utility has an overhead corridor to install the spacer cable.

Spacer cable will not eliminate all outages. Trees that are large enough can still take the spacer cable off the pole or even break poles. The Company applies a consistent approach to spacer cable analysis when estimating the saved Customer Minutes of Interruption ("CMI") based upon past reliability performance:

- 50% savings in CMI for outages caused by animals
- 80% savings in CMI for outages caused by fallen tree limbs
- 50% savings in CMI for outages caused by fallen tree trunks
- 80% savings in CMI for outages caused by tree growth into the line
- 50% savings in CMI for outages caused by uprooted trees
- 80% savings in CMI for outages caused by vines

Targeted Undergrounding

Targeted undergrounding is a preferred option for areas of high tree density, where the Company cannot get trimming rights and spacer cable is not an option. Targeted undergrounding is generally done over several spans or up to as much as a mile. Targeted undergrounding will eliminate 100% of tree related outages since all of the cable is buried. Targeted undergrounding tends to be a more-costly option[53] than either spacer cable or bare overhead construction. However, in targeted cases, undergrounding is a good solution to improving the resilience of the electric system.

Targeted undergrounding comes with some challenges as well. Replacing an existing overhead line with an underground cable requires:

- Assignment of an underground location for the cable and conduit by the city/town;
- Replacement of all overhead transformers with padmounted transformers, which may require easements from landowners;
- Replacement of overhead services with underground services, which may require easements from landowners;

[53] Targeted underground costs can range from $4 million to $6 million per mile depending upon the complexity of the design, number of lateral taps, quantity of customers connected and the number of transformers.

- Replacement of meter socket from an overhead entrance to an underground entrance; and
- Replacement of pole-mounted equipment (i.e. switches, reclosers, fused cutouts, etc.) with padmounted equipment, which may require easements from landowners.

Recommended Increase in Reliability and Resiliency Spending

In this plan, the Company is proposing to increase spending on its targeted spacer cable and undergrounding projects by a combined $1.0 million in an effort to increase the overall resiliency of the electric system. This level of funding will support the installation of approximately 2 miles of spacer cable or 700 to 1,800 feet of targeted undergrounding. This spending may also be used for developing circuit ties where they do not exist or automating circuit ties where they do exist.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	**$5,000**
O&M Costs (000s)	$ 0	$ 0	$ 0	$ 0	$ 0	**$0**
Total Costs (000s)	**$ 1,000**	**$ 1,000**	**$ 1,000**	**$ 1,000**	**$ 1,000**	**$5,000**

Table 73 – Proposed Reliability and Resiliency Spending

Customer Benefits

Though it will significantly reduce outages, unlike targeted undergrounding, spacer cable will not eliminate all outages. Trees that are large enough can still take the spacer cable off the pole or even break poles. The Company applies a consistent approach to spacer cable analysis when estimating the saved Customer Minutes of Interruption ("CMI") based upon past reliability performance:

- 50% savings in CMI for outages caused by animals
- 80% savings in CMI for outages caused by fallen tree limbs
- 50% savings in CMI for outages caused by fallen tree trunks
- 80% savings in CMI for outages caused by tree growth into the line
- 50% savings in CMI for outages caused by uprooted trees
- 80% savings in CMI for outages caused by vines

Improving the resilience of the system also results in less damage during storm events. Less damage results in shorter outages, fewer crews and a less costly overall restoration.

10.4 ASSET CLIMATE VULNERABILITY ASSESSMENT (SUCH AS FLOOD IMPACTS, WIND SPEEDS, HIGH HEAT IMPACTS, ICE ACCRETION, WILDFIRE AND DROUGHT)

Climate-related risks and opportunities are reflected in our strategic planning processes. Operations, and operating excellence, are critical to and driven by the Company's mission and vision, which include deliberate consideration for sustainability, and climate change risk and opportunity. The Company's Mission "to safely and reliably deliver energy for life and provide our customers with affordable and sustainable energy solutions" recognizes the critical importance of our energy delivery services and also considers the lasting value sustainability creates for our stakeholders. The Company's Vision Statement, "to transform the way people meet their evolving energy needs to create a clean and sustainable future" is heavily influenced by climate related risks and opportunities.

Our Strategic Planning Process includes an annual review of industry drivers, continuous improvement Mission objectives, and strategies to achieve our Vision. The objective of climate vulnerability assessment is to preserve our Company's long-term sustainable value by preparing for plausible climate-related scenarios, and successfully adapting and transitioning to a low-carbon economy. The strategy is to Identify, assess, and prioritize physical and transition risks associated with climate change; develop plans to manage or mitigate risk; and capitalize on opportunities. This approach to risk assessment is integral to our strategic planning process, and leverages the diverse perspectives brought by our team members. We will continue to update our scenario planning process and modeling techniques to refine our scenarios, test our strategies against them, and develop plans to address risks.

Unitil's Strategic Planning Committee engaged its Strategic Management Group in a multi-day exercise to perform two separate climate scenario analyses: one that aggressively models high emissions and climate impacts to the region (RCP 8.5),[54] and one that forecasts drastically curbed emissions and a milder outcome (RCP 2.6).[55] Members were asked to review scenario specific supporting data and project operational, organizational, and financial impacts in each case. Members were divided into groups with balanced cross functional expertise and tasked with

[54] RCP 8.5 refers to the concentration of carbon that delivers global warming at an average of 8.5 watts per square meter across the planet. The RCP 8.5 pathway delivers a temperature increase of about 4.3˚C by 2100, relative to pre-industrial temperatures. RCP stands for Representative Concentration Pathways.

[55] RCP 2.6 (also referred to as RCP3-PD) is the lowest in terms of radiative forcing among the four representative concentration pathways. This particular scenario is developed by the IMAGE modeling team of the Netherlands Environmental Assessment Agency (Van Vuuren et al., 2007).

targeting specific focus areas with the purpose of making suggestions on both risk mitigation and the pursuit of opportunities. Results were compiled, ranked by intensity across a risk mitigation "heat map", and reviewed to establish common themes, priorities, and alignment to the Strategic Pillars contained within the Company's existing strategic planning documents.

To understand how climate-related risks may affect our business and to properly prepare for them, we analyzed where and how our operations could be affected. We used two risk categories – those that may have physical impact and those that may have a transitional impact. Physical risks are weather related and impact our assets, such as sea level rise, storms, and temperature extremes. The figure below maps the Company's substation assets against the FEMA floodplains.

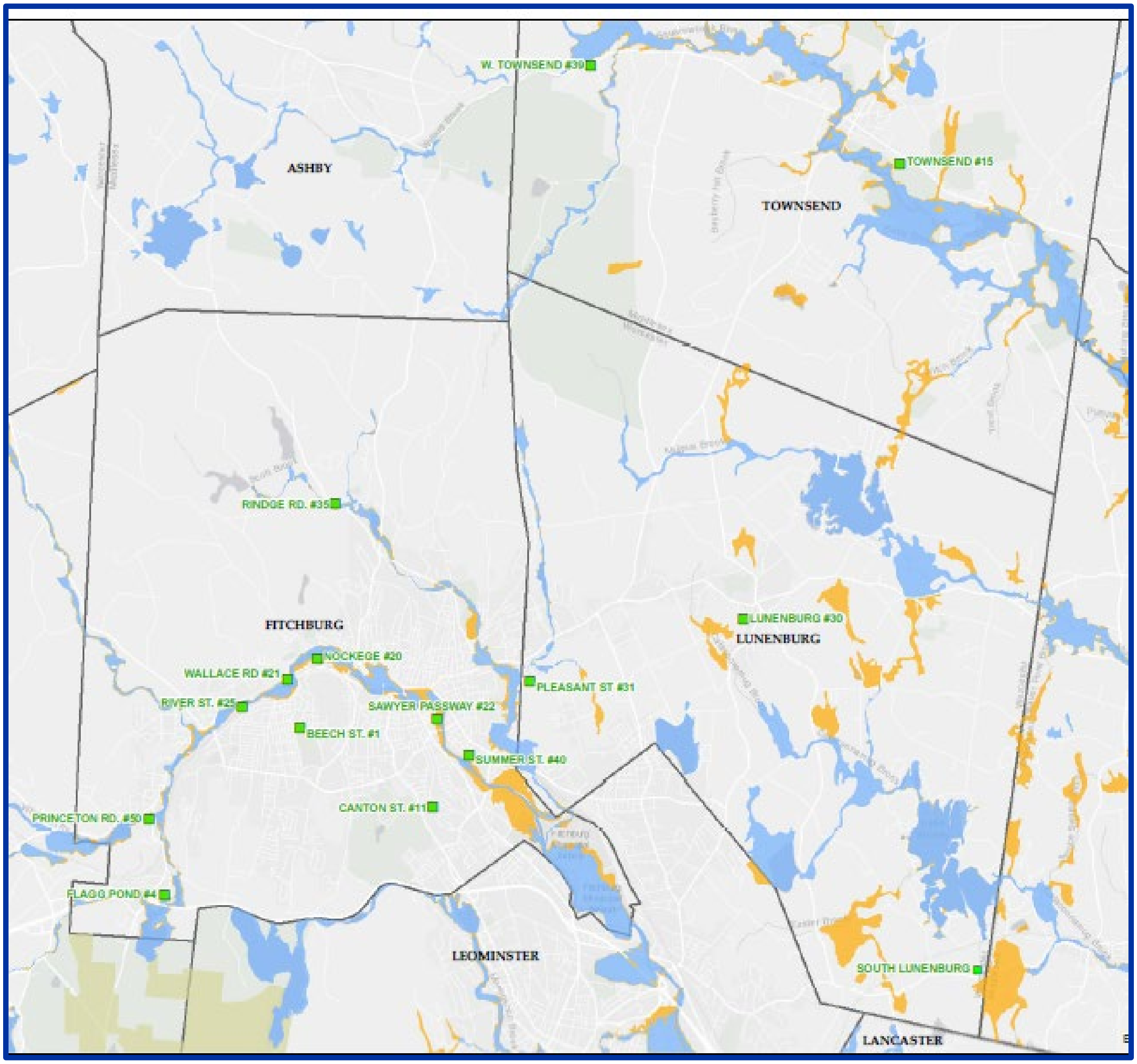

Figure 59 – FEMA Floodplain Mapping Showing Substations

Transitional risk includes business risks and opportunities that come from the impacts from climate change or the shift to decarbonization. The eleven areas most relevant to our Company and geographic location are included in the table below.

Physical Risks	Transitional Risks
Sea level rise, Coastal Flooding and Storm Surge	Policy, Legal and Regulatory
Fluvial (River) Flooding	Market
Hurricanes and Storms	Technology
Temperature Extremes	Reputation
Wildfire	
Change in Precipitation	
Change in Mean Temperature	

Table 74 – Material Risk Areas

The results of the climate-related scenario analysis were an understanding of which physical and transitional risks under which Representative Concentration Pathways (RCPs) are material to the company, and which of these risk areas have the highest risk prioritization. Seven physical risks and 4 transitional risks for two RCP scenarios (11 total cases) were identified for company specific assessment. This assessment included identifying the likelihood and impact to the company as well as the risks, mitigating actions, and opportunities associated with each. Of those 22 cases, 6 were identified as posing the highest likelihood and impact to the Company. These were Technology; and Policy, Legal, and Regulatory under RCP 2.6 and Temperature Extremes; Hurricanes and Storms; Reputation; and Change in Mean Temperature under RCP 8.5. For each of these 6 cases, the identified risks, mitigating actions, and opportunities faced were reviewed for inclusion in current strategic planning initiatives. Each of these areas were reviewed for additional data and input need and are incorporated into an internal strategic planning project management plan to continue analysis and further inform strategic planning.

For each risk, we assessed the likelihood of occurrence, the impact severity, potential and ongoing mitigation options, and future opportunities. During the assessment process, we recognized the need for more detailed information and physical climate projections. To date, we have completed a detailed analysis on two physical risks - sea level rise and temperature extremes. Sea level rise is more concerning for the Company's New Hampshire affiliate than it is for the Company due to location.

Using scenario modeling, we are able to evaluate the probability of impact associated with a potential future date. We then can determine which scenario and rise level is most probable, and assess and manage for impacts on our system. For example, two feet of rise is only possible in some scenarios (2050 using RCP 4.5) while very likely under others (2100 using RCP 8.5). The most extreme effect modeled, eight feet of rise, is unlikely under all scenarios except the most extreme scenario in which there is less than a 0.5% probability of occurring in 2100.

In response to the findings from this assessment, the Company will be evaluating the following:

- Evaluate equipment loading guidelines specific to loading cycle and ambient temperature to determine the impacts ambient temperature will have on the overall ratings of various types of equipment. This may have an impact of changing system planning guidelines and equipment loading guidelines.
- Evaluate overhead line design standards for increase ice accretion and wind speeds to determine the effect on the conductors, poles and other supporting equipment. This may have the impact of modifying distribution and transmission construction standards to address changes in maximum expected wind forces and ice accretion.
- Evaluate areas of potential inland flooding concerns (i.e. along existing rivers and streams) to determine when flood mitigation measures are required. This may have an impact on substation design standards.
- Install targeted undergrounding in areas where traditional or even enhanced vegetation management activities are not successful. This may have an impact on reliability planning standards using an approach to avoid damage due to increasing storm severity.
- Increase the quantity of circuit ties and implement FLISR schemes to automatically isolate and restore outages. This may have an impact on reliability planning standards.

The work completed by Unitil to date is the first step in a detailed process for evaluating the effect climate change may have on the electric system. The Company is still evaluating the resources and timeframe required to address all aspects of a climate vulnerability plan. The Company will take an iterative approach to prioritizing and executing detailed analysis in specific areas in an attempt to address the most critical items first. The Company provides public information on its climate vulnerability assessment in its annual sustainability report.

10.5 FRAMEWORK TO ADDRESS CLIMATE VULNERABILITY RISKS THROUGH RESILIENCE PLANS

The Company is in the early stages of designing and implementing an iterative framework to assess the risks associated with climate change. The goal of the framework is to identify areas of risk, implement mitigation measures to reduce risk and improve the resilience of the system. The following high-level steps describe the framework:

1. Vulnerability Assessment - The Company's approach to address climate vulnerability and develop resilience plans begins with the climate vulnerability assessment described in the previous section.
2. Evaluate and Prioritize Risk – The Company is now evaluating and prioritizing the relative risks associated with each scenario.
3. Develop and Evaluate Mitigation Options – Once the risks have been prioritized, the next step is to develop mitigation strategies to address and mitigate the risk identified. In evaluating the mitigation options, the Company will consider and prioritize the impact the mitigation and benefit has on EJCs and low- to moderate-income customers.
4. Prioritize Implementation of Mitigation Options – Once the mitigation strategies are identified, each of the strategies should be prioritized and implemented in order;
5. Evaluate Success – The Company must evaluate the success of the mitigations implemented to ensure the mitigations are providing the expected improvements to reliability.
6. Repeat Vulnerability Assessment – Following the implementation of mitigation strategies, the Company must conduct the vulnerability assessment again to identify and evaluate and new or emerging threats that may not have been identified in the last assessment.

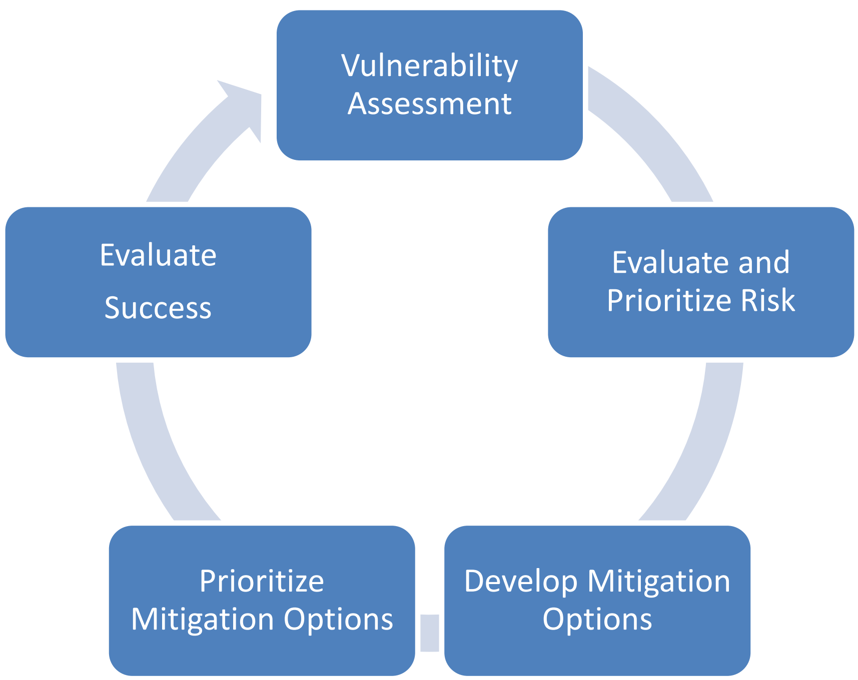

Figure 60 – Climate Vulnerability Assessment Framework

Distribution planning and design standards are critical components to safe and reliable design and operation of the electric system. These standards are based upon industry best practices as well as historical weather conditions (i.e. ice, wind, and temperature). Climate change may have an impact on planning and design standards as industry best practices change to account for changes in future weather conditions.

The Company, when designing the mitigation options, will consider the risk of climate change and not just past performance as an indicator of future performance. Climate change will continue and risk will continue to present themselves. The iterative framework will ensure the Company remains focused on new and emerging risks to the resilience of the system.

11 INTEGRATED GAS-ELECTRIC PLANNING

Gas and electric utilities generally plan and operate their networks in isolation from one another even when they are affiliated companies within a common parent company because historically there has been little need for coordination. Moreover, customer demand-side programs have not traditionally been closely integrated with infrastructure planning. Integrated energy planning can support the decarbonization goals of the Commonwealth while providing gas and electric customers with safe, reliable, and affordable service. Electrification of gas customers not coupled with the necessary electric infrastructure improvements may result in an unreliable grid. As such, the Company is evaluating integrated gas-electric planning as a tool to ensure safe, reliable, and affordable service to our gas and electric customers.

An orderly coordination and collaboration on gas and electric system planning and customer demand-side programs offers opportunities to optimize overall energy system costs and reliability. With seamless exchange of gas and electric forecasts, LDC and EDC capital investment plans can identify synergies and opportunities in the development of their capital plans. Integrated planning will help enable the Commonwealth collectively to:

a) Prudently build out the electric system in the right locations at the right time to prepare for the electrification of heating loads and
b) Make calculated decisions about where to prioritize investment in the gas and electric networks.

Integrated planning is a tactical toolkit to evaluate and shape where, why, how much, and by when to make critical investments in gas and electric networks so that gas and electric utilities have a shared plan for how to meet the heating needs of customers.

11.1 CHALLENGES IN CONSIDERING INTEGRATED GAS-ELECTRIC PLANNING

As highlighted in the prior sections, areas of the electric distribution system are approaching planning limits – which require imminent upgrades. Construction of such upgrades, especially for new substations, can take as long as 5 years or more. Similarly, multiple areas on the natural gas distribution and upstream systems have constraints imposing reliability and safety risks. The existing planning of the gas and electric systems have traditionally been bifurcated. There is now a convergence of the systems as heating and transportation sectors consider a transition to electrification. Further complicating this is that the footprints of EDCs and LDCs do not completely overlap necessitating integrated planning to be coordinated across utilities – and their associated electric and gas network upgrade plans. Key challenge areas that need to be overcome:

1. **People, Process, Technology:** While utilities have planning staff on the gas and electric sides of the business, their skillsets, the tools they use, the planning standards, and the overall capital planning processes across utilities and even between EDCs and LDCs are different. This is to be expected with past practices requiring little to no coordination of planning efforts even across affiliated operating companies. The first challenge in implementing a coordinated Energy Planning process is to assess these differences through a common understanding and drive alignment such that a foundation of a coordinated planning between the EDCs and LDCs across utilities can be established.
2. **Limited-service territory overlap**: To understand the limited degree to which affiliated gas and electric utilities' service territories overlap, it helpful to look at the share of gas customers served by the affiliated EDC since electricity service is universal. Only 28% of National Grid's gas customers are also National Grid electricity customers. Similarly, only about 50% of Eversource's gas customers are also Eversource electricity customers. Unitil is positioned somewhat differently in that 86% of its gas customers are also Unitil's electricity customers. Nevertheless, the level of overlap between gas and electric networks drives the need for coordinated utility planning. More specifically, when a constraint is identified on the gas system, in order to reduce that gas demand with deployment of electrification solutions, another EDC may need to upgrade their electric infrastructure – necessitating a comprehensive data exchange between the LDCs and EDCs regardless of their company affiliation.
3. **Customer adoption** Electric and gas utilities can transform their capabilities for integrated planning with the most robust processes, software, and data for developing plans. Plans to optimize across gas and electric network investments will ensure that safe and reliable electric and gas networks are maintained for customers, but will not come to fruition if customers do not adopt electrification and do not transition from gas usage when and where a system need is identified. For example, decommissioning a segment of leak prone pipe requires that every individual customer on that section of pipeline disconnect from gas and install new electric equipment by a date certain.
    a. The current approach to demand side electrification incentive programs does not provide for this orderly transition because time-bound, universal adoption of heat pumps, electric boilers, and electric stoves by customers served by specific gas infrastructure is a new objective that raises important program design and implementation questions. The customer impact needs to be evaluated and addressed which may require additional incentives or program redesign for customers to feel comfortable with the transition from gas to electricity.

   b. While an organic customer adoption of electrification solutions is imperative for a sustainable path toward decarbonization, to drive an orderly transition, more coordination is needed to ensure available electric infrastructure electrification hosting capacity is calibrated with electrification deployment. Given that there may be a substantial number of customers currently served by gas, adoption of electric technologies, at current retail rates, will in most instances increase their overall energy burden. Therefore, where applicable, rate redesign may also be necessary to ensure an affordable transition to electrification.
   c. The utilities look forward to hearing stakeholder feedback on, in the context of the ESMP. Moreover, the Mass Save Program Administrators are committed to developing ways to best address the equitable adoption of heat pump technology and other energy efficiency technologies and will continue to develop these proposals in the Energy Efficiency Three Year Plans, in concert with the Energy Efficiency Advisory Council and Equity Working Group members and subject to the approval of the DPU.
4. Integrated planning requires answering novel questions about the interplay of customer adoption/legacy building stock electrification, electricity network capacity expansion, and gas system modernization, reinforcement, or decommissioning. Today's industry standard data, tools, and planning processes are not designed to answer these questions. The preceding sections provide some early indication of potential strategies to help address these challenges.

11.2 TRANSPARENT ELECTRIC SECTOR MODERNIZATION PLAN

The ESMPs provide an important first step in enhancing the transparency of electricity network investment plans and the rationale for them among the Commonwealth's utilities. This transparency can be the basis for building out integrated planning. This information can inform utility planning processes and pave the way for information sharing on the status of electric system plans with gas utilities. The ESMPs also create more transparency among a broader set of Commonwealth stakeholders of the immediate network investment plans for the EDCs. This information can inform the gas planning process and pave the way for some very basic information sharing on the status of the electric system plans.

More specifically, this ESMP provides a 10-year view of available electrification load-serving capacity in each sub-region served by the Company within the Commonwealth. And because of various upgrades implemented in different years within the 10-year period, a sub-region's available electrification hosting capacity may increase over the forecasting period.

11.3 COORDINATED GAS-ELECTRIC PLANNING PROCESS

Although the ultimate process still needs to be fully defined based on pilots, learning, and stakeholder collaboration, several things seem clear about how IEP should work:

- Understanding where electricity networks have sufficient headroom now and in the future to handle localized incremental heat electrification demand and where the networks face localized constraints will be important for gas LDCs as they comply with the Department's directives in D.P.U. 20-80 regarding evaluating future gas system investments against non-pipe alternatives.[56]
- The pace and prioritization of specific electricity network investments should be based in part on identified opportunities to avoid gas system investments where accelerated comprehensive electrification can avoid gas network reinforcements or allow for targeted decommissioning of gas assets.
- Utilities should find discrete opportunities to pilot non-pipe alternatives where electricity networks can support universal comprehensive electrification (or other gas network disconnection) to decommission gas segments or avoid gas network reinforcement.
- Orderly customer adoption is necessary to realize the benefits of IEP:
  - Customer demand-side programs should be coordinated with gas/electric investment plans, including to target comprehensive electrification where it reduces overall system costs;
  - New policies and regulations may be needed to facilitate universal gas network customer disconnection in targeted areas to allow for strategically decommissioning gas assets (e.g., leak-prone pipe infrastructure).
- Where specific gas constraints are identified and electrification hosting capacity is unable to be increased in the required time such that electrification of customer loads could resolve the gas constraint, alternative solutions (e.g., increased adoption of EE, flexible battery storage, green hydrogen), and other customer-side decarbonization solutions may be necessary.
- Further, where communities are opting for a moratorium on gas or where existing gas infrastructure is constrained, and corresponding practical moratoriums are in effect, new electric technology pilots could help further the communities' decarbonization goals – thereby avoiding the need for new gas infrastructure.

[56] D.P.U. 20-80-B *Order on Regulatory Principles and Framework*, at 15.

- Stakeholder input will be essential to coordinated planning, including giving affected communities a voice in the planning.

Unitil will use a case study and pilot project approach to identify the feasibility and implementation timing of upgrading the electric infrastructure coupled with the timing of targeted customer electrification to provide a coordinated and optimized approach to support statewide greenhouse gas emissions goals. Specifically, the case study and pilot project approach will prioritize locations where gas infrastructure upgrades (i.e. GSEP replacement) may be eliminated by prioritizing the Intermediate Pressure and Low-Pressure pipeline systems.

Planned Implementation:

a. **Case Study Phase:** Unitil will focus within Unitil Gas-Electric overlap service areas to identify one potential candidate for neighborhood electrification. The Company will complete an integrated electric and gas system planning case study to develop the design, costs, benefits, and challenges associated with neighborhood electrification. The case study phase would begin in Q1 2024.
b. **Pilot Project Phase:** Assuming that the case study produces beneficial results, the Company will propose and conduct a pilot project to verify the case study findings. Unitil's pilot project proposal would be submitted to the Department for approval in line with Order D.P.U. 20-80 (March 2026). The project would commence following authorization by the Department.
c. **Expansion Phase:** Expand to areas outside of Unitil electric and gas overlap area to test scalability of processes. Test electric service territory only, with coordination with other EDCs.

The outcome of the pilot project will be used as a basis to identify future locations where electrification would be beneficial as a non-pipes alternative. Future gas infrastructure projects would then be evaluated against non-pipe alternatives in selecting the most cost-effective solution to provide safe and reliable service to our customers.

Process:

Joint Utility Planning Working Group – Establishing a Joint Utility Planning Working Group can help to maintain a coordinated approach to developing capital plans.

- Establishment of Cross Utility (LDC and EDC) Planning Working Group.
- Ongoing Working Group meetings– formal meetings to be established every 2 months with broad stakeholder participation.
- Ultimate objective would be to enable development of coordinated EDC-LDC Capital Plan.

LDC-EDC Data Exchange – In order for EDC-LDC coordinated planning to be successful, the following information must be exchanged:

- Detailed data on legacy Commonwealth building stock and electrification suitability and anticipated demand.
- Exchange of residential and commercial hourly heating usage data – translated to distribution feeder electrification data (accounting for weather conditions, technologies and building envelop ratings, current and forecasted).
- Exchange of gas and electric capital upgrade plans by year between EDCs/LDCs with supporting planning analyses and reports.

Planning Tools:

Planning Tools – The following software and planning tools will be required.

- Software tools that translate geographic gas demand with consideration of various weather associated gas demand scenarios into electric system loadings – with embedded assumptions of different electrification technologies.
- Translating those electric loading scenarios through a GIS interface into Distribution Planning models.

People:

- While LDCs and EDCs are staffed to develop their respective investment plans in the traditional way, executing on the coordination process laid out above, engaging with stakeholders on IEP, delivering on IEP pilots, soliciting customer and community input on plans, and providing visibility to the Department on IEP will require incremental staff for the EDCs and LDCs.

The EDCs and stakeholders should think through and define a long-term "future state" for IEP—i.e., what IEP delivers once it is a fully developed capability for overall energy system optimization, with enabling policy and regulatory frameworks and supporting customer and community input and engagement. However, that long-term view should not get in the way of making tangible progress in the near term. IEP will be an evolution over years. Near-term efforts can identify where looking across electricity and gas network investments and customer demand-side programs in new ways can improve pending investment decisions. One example of a near-term opportunity is the need for both affiliated and non-affiliated overlapping gas LDCs and EDCs to collaborate on exploring non-pipe alternatives to gas network investments and targeted electrification pilots, where the Department's order in D.P.U. 20-80 "directs each LDC to work with the relevant electric distribution company to study the feasibility of piloting a targeted electrification project in its service territory."[57]

11.4 SAFE AND RELIABLE GAS INFRASTRUCTURE

The Company is required to provide safe and reliable service at a reasonable rate to our gas and electric customers. Integrated energy planning is necessary to identify and support the safe and reliable transition of gas loads to electric loads. Any scenario for transitioning customer demand from natural gas to electric heating takes decades to implement, during which time gas utilities will need to continue to make investments in maintaining safe and reliable service and reducing fugitive methane emissions, especially by replacing leak-prone pipe infrastructure. Those investments are driven in large part by current state and federal safety regulations.

11.5 COORDINATED INTEGRATED ENERGY PLANNING WORKING GROUPS (GOALS, OBJECTIVES, ACTIONS, AND TIMELINES)

As noted earlier, the effectiveness of integrated gas and electric planning will be significantly limited if there is a lack of cross-commodity coordination among peer utilities, including investor-owned utilities and municipally operated ones. Failure to establish appropriate cross-utility collaboration and data sharing frameworks means that the majority of the Commonwealth would not have any integrated gas and electric planning, and thus would not benefit from well-coordinated gas and electric plans. Unitil looks forward to working with the other utilities on a coordinated approach to integrated planning.

Thus, establishing a gas and electric coordinated planning working group with representatives from the different Commonwealth electric and gas utilities, MA DOER, AGO, and key affected stakeholders (e.g., environmental, consumer) will be critical. The Department endorsed such a stakeholder-focused approach in the recent D.P.U. 20-80 order, explaining that "[t]he Department emphasizes that joint electric and gas utility planning must occur in a broad stakeholder context so that the LDCs and electric distribution companies exclusively are not defining the process and outcome" and that "[t]he LDCs and electric distribution companies should consult with stakeholders regarding such a joint planning process."[58]

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[57] D.P.U. 20-80-B *Order on Regulatory Principles and Framework*, at 15.
[58] D.P.U. 20-80-B *Order on Regulatory Principles and Framework*, at 131.

The working group's objectives should include:

- Develop a shared understanding of the overlapping commodity owners' networks today and their network planning processes.
- Leverage learnings and best practices from other leading utilities in this space
- Conduct joint energy planning studies to generate learnings and identify near-term opportunities to optimize investments, such as:
    i. Exchange of gas and electric distribution constraints
    ii. Conduct and share planning studies to resolve constraints
    iii. Detail investigation of gas-customer electrification scenarios to assess resulting electric infrastructure constraints and corresponding assessment of offsetting gas constraints
    iv. Identification of specific gas and electric planning solutions
- Develop a shared understanding of required integrated planning capabilities including changes needed in processes, technology, people, and data.
- Agree on a prioritized roadmap to develop such capabilities (i.e., what are low hanging fruits to focus on first, and what are the transformational capabilities to go from IEP "light" to more comprehensive plans in the longer term).
- Establish an analytical framework for assessing the benefits of integrated planning.
- Provide recommendations for how the three-year energy efficiency program process should align with integrated energy planning.
- Assess future regulatory decisions as well as identify additional policy and regulatory enablers for integrated planning.
- Explore how best to provide transparency and opportunities for input to various stakeholders.

11.6 MILESTONES

The following milestones are contemplated as part of this joint planning effort.
The following milestones are contemplated as part of this joint planning effort.

- Q1 2024 – Work begins with EDCs and LDCs to develop cross-utility coordination approach to integrated planning.
- Q1 2024 – Q4 2024 – Complete case study phase for a neighborhood electrification pilot.
- Q1 2025 – Q4 2025 – Develop detailed pilot neighborhood electrification pilot project.
- Q1 2026 – File neighborhood electrification pilot project with Department for pre-authorization
- After Department Pre-Authorization – Complete neighborhood electrification pilot project following pre-authorization by the Department.

Unitil looks forward to working with the other utilities on a coordinated approach to integrated planning.

11.7 NEXT STEPS

Pending Department review of the stated objectives, proposed process, and approval of necessary investments in people, process, data, and technologies necessary to execute on IEP, the EDCs will: (1) proceed with the establishment of the Joint Utility Planning Working Group, including reporting out to GMAC on an agreed upon cadence; and (2) pursue the near-term opportunities to engage in IEP, particularly EDC and gas LDC collaboration on non-pipe alternatives and targeted electrification pilots. Unitil looks forward to working with the other utilities on a coordinated approach to integrated planning.

12 WORKFORCE, ECONOMIC, AND HEALTH BENEFITS

Electric sector modernization will not be successful unless and until the workforce is assembled and trained. Technology is swiftly advancing and the rapid growth will increase the quantity of technical and non-technical jobs, increasing the opportunity for training and growth within the workforce.

Investments in modernizing the electric system provide workforce, economic and health benefits to customers and the communities that we service. These benefits are not limited to any particular subset of our customer base. An increase in good paying jobs at all levels of skill and education are required to modernize the electric system. A large portion of the Company's service territory is located within an EJ community. Therefore, the increase in good paying jobs will offer local economic opportunities to individuals within the EJCs. This in turn will stimulate the local communities and spur improvements in housing and transportation that may not have otherwise been attainable within the same timeframe.

12.1 OVERVIEW OF KEY IMPACT AREAS

The Company has identified a series of eight objectives that together ensure support of a modern energy ecosystem. Our objectives are crafted with guidance from the Department and the United States Department of Energy, and regulators in the Company's affiliate jurisdictions, and are used to identify the investments and technologies that best serve this new era.

Objective 1: Environmentally Friendly – We must firmly support the region's goals in reducing emissions in the battle against climate change.

Lower GHG emissions and reduced air pollution will improve the health of our customers and communities. We believe utilities must enable the integration of renewable energy projects that will deliver emission-free solar, wind and hydro power to our region. We support energy efficiency and time-of-use initiatives which allow customers to take control of their own usage, further lowering GHG emissions. We educate and empower customers to shift their energy usage away from peak times of need, an action that not only provides substantial environmental benefits, but reduces overall demand and allows the system as a whole to operate more efficiently. Land use impacts and mitigation are considerations for every project with specific focus on the impact to EJ communities.

Objective 2: Safety, Reliability and Resiliency – We must continuously improve safety, reliability and resilience while reducing the effects of outages.

Providing safe, reliable and resilient service at an affordable cost to all customers is central to the Company's mission. As the grid continues to experience more severe weather due to climate change, building a resilient and reliable grid is critical to the future success of the communities we serve. The grid must be operated in a manner that ensures public and employee safety. Improved reliability, communications and resiliency is required to support electrification. Electricity must be delivered at a safe, stable, consistent voltage optimized for use by homes and businesses, and outages must be kept to a minimum. When storms do occur, the system must be built in a way that restoration can occur rapidly and efficiently.

Objective 3: Customer Service – We must improve and embrace customer empowerment, engagement, and education. We must give the customer the tools they need to understand and control both their own energy usage and energy matters in the region.

As more and more at-home innovations evolve the way we use electricity, there is a growing customer need for a trusted energy advisor. Access to personal data on energy usage will help to empower customers to actively manage and understand their own technology and usage decisions, resulting in lower bills. Electric vehicles, heat pumps, smart appliances and energy management systems are changing the manner in which customers utilize energy and interact with the system. Home energy management systems require real-time information to help customers make decisions on how to optimize energy usage at home. Electric vehicle rate structures will help customers program when charging occurs and plan accordingly.

Objective 4: Security – We must ensure the cyber and physical security of the grid remains strong.

Strong cyber and physical security are cornerstones in ensuring the safety and reliability central to our mission. The modern grid must reduce physical and cyber vulnerabilities while also enabling rapid recovery from disruptions. The secure sharing and rapid analyzation of accurate information will be central to a modernized energy ecosystem and the development of new energy markets and services. Data security and customer privacy must be carefully integrated into existing operational practices.

Objective 5: Flexibility – We must ensure the grid remains flexible enough to accommodate and integrate all types of new energy sources.

Transportation and building electrification, energy storage and the integration of DERs are making the flow of electricity in cities and neighborhoods more complex. Managing this flow will require a smart, flexible system that not only makes interconnections easier for end-users, but allow system operators to rapidly switch over to utility-scale, reliability focused energy suppliers when required. The grid should be designed in such a manner to avoid curtailment of renewable energy due to constraints on the system. The timely adoption and integration of renewable resources and distributed energy resources is beneficial to the environment.

Objective 6: Affordability – Energy for life must remain affordable for all.

Ensuring fair prices is central to any modern grid design model. By ensuring our system infrastructure is a flexible, enabling platform, we are able to integrate customers with competitive markets and other service providers to enable the delivery of affordable energy choices for all. Such a system gives customers the opportunity to make decisions on how they use the grid, when they use the grid, and how best to maximize value. Minimizing and mitigating the impact on the ratepayers, and especially low and moderate income ratepayers, supports the overall goals of reduced greenhouse gas emissions.

Objective 7: Demand and Asset Optimization – The grid must be designed to get the most out of the tools and resources interconnected in order to best serve the region.

When renewable energy systems are connected to the electric system, we want to ensure interconnections are optimized for both the generator and end-users. The modern grid has advanced tools and technology in place to optimize system performance and improve the grid's performance from reliability, environmental, efficiency and economic perspectives. System demand is reduced through greater efficiency to control total system costs for generation, transmission and distribution. Advanced system planning tools will integrate the benefits of distributed energy resources and identify locations where these assets can be optimized. The objective here is to not necessarily operate all equipment to their ratings or limits. Rather, assets will be managed to only deliver what is required at the time. Real-time data will provide the information required to reduce operating and maintenance costs along with the environmental benefits associated with improved efficiency and fewer failures. Promotion of energy storage and electrification technologies is necessary to decarbonize the environment and the economy.

Objective 8: Technology Innovation – The grid must enable the easy adoption of new technologies as they are developed to further support customer choice and system operations.

Effective technology and secure data sharing are crucial to operating a transparent and open energy system. Customers and other users want to make informed decisions on their energy needs, and data from the Energy Hub makes sharing simple and intuitive. Developers, meanwhile, need clear rules for how to interconnect renewable energy projects as well as an understanding of where interconnections would maximize the value to the system.

There are inherent complexities and challenges associated with supporting each objective individually without considering the whole. Offering customers more technologies and increased data sharing can potentially increase risk of cyberattacks, which in turn creates security challenges. The early adoption of some emerging technologies can come at a premium, and associated costs create conflicts with the goal of keeping energy affordable. The intermittent nature of some forms of renewable energy sources can be at odds with the reliable service our customers expect.

It is in recognizing the push and pull these objectives have on one another where the maximum benefit to all customers can be found. The system must be operated in a manner which optimizes the benefits for all while ensuring all voices and viewpoints are heard and represented. Balancing all objectives is the key to unlocking this utility future state we aspire towards. The table below maps the existing and proposed projects to the objectives.

Project Or Functionality	**Existing / Planned**	**Environmentally Friendly**	**Safety, Reliability, and Resiliency**	**Customer Enablement**	**Security**	**Flexibility**	**Affordability**	**Demand and Asset Optimization**	**Technical Innovation**
Base Capital Budget	Existing	X	X	X	X	X	X	X	X
Enable Grid Services	Planned	X	X	X	X	X	X	X	X
ADMS/DERMS	Existing and Planned	X	X	X	X	X	X	X	X
VVO	Existing and Planned	X	X	X		X	X	X	X
SCADA Automation	Existing and Planned		X	X	X	X	X	X	X
Cyber Security	Planned		X	X	X				X
FERC 2222 implementation	Planned	X	X	X		X	X	X	X
Lunenburg Substation	Planned	X	X	X	X	X	X	X	X
South Lunenburg Substation	Planned	X	X	X	X	X	X	X	X

EV Charging and Make Ready	Existing and Planned	X	X	X	X	X	X	X	X
Targeted Reliability and Resiliency	Existing and Planned		X	X	X		X	X	X
Energy Efficiency	Existing and Planned	X		X	X	X	X	X	X

Table 75 – Mapping Projects to Objectives

This Plan enables workforce, economic, and health benefits for our customers, the communities we serve and the Commonwealth. The benefits from this plan are based upon a net benefits analysis performed by a third party. The analysis considered three categories of benefits including monetized benefits, non-monetized benefits and qualitative benefits.

The EDCs have collaboratively employed the Regional Input-Output Modeling System II (RIMS-II),[59] a tool developed by the United States Department of Commerce – Bureau of Economic Analysis (BEA) to complete a jobs and economic impact analysis. This approach leverages a region-specific capital multiplier for Massachusetts, ensuring a tailored evaluation of the economic impact. The EDCs' joint effort in this analysis underscores a commitment to understanding and maximizing the positive economic effects of their investments across the Commonwealth, reinforcing the collaborative approach in driving regional economic development.

12.2 JOBS TRAINING AND IMPACTS TO DISADVANTAGED COMMUNITIES

The Massachusetts Clean Energy Center released a report on the workforce needs to support the clean energy goals of the Commonwealth.[60] The report concluded that the existing workforce cannot support the clean energy goals of the Commonwealth and through modeling has determined that over 38,000 additional workers will be required to support the transition; 3,794 jobs in the transmission and distribution sector. The Commonwealth's 2050 Decarbonization Roadmap Study estimates an increase of 18,000 jobs in the distribution and transmission sector

[59] "*RIMS II Input-Output Model User Guide*." Bureau of Economic Analysis, https://www.bea.gov/sites/default/files/methodologies/RIMSII_User_Guide.pdf

[60] Powering the Future: A Massachusetts Clean Energy Workforce Needs Assessment, dated July 2023. Powering the Future A Massachusetts Clean Energy Workforce Needs Assessment_Final.pdf (masscec.com)

by 2050.[61] The Commonwealth's Clean Energy Climate Plan to 2050 and 2030 identifies the addition of over 16,000 jobs in the distribution and transmission sectors by 2050.[62] There are many models with many different assumptions used to develop these estimates.

The Company supports the idea that more workers will be required and the skills of these workers may differ from existing skills. For instance, distribution equipment has become more computer based relying on communication networks that have historically not been used in the field. Field staff will need to be trained in the installation, programming, testing and troubleshooting of communications equipment (radios, routers, modems, antenna, etc.) and controls.

The Company has a long history of hiring, training, and retaining the workforce necessary to provide safe and reliable service to our customers. The Company's focus on knowledge and experience has proven to be an effective approach to controlling costs. The Company's field workforce is typically covered by union labor agreements while the office and technical staff is a non-union workforce. The Company benefits from Unitil Service Company which provides a shared workforce of technical and administrative services between the Company and its affiliates. The Company began its transition to a more technical electric system when it first installed AMI on its system over 15 years ago and has employed union workers, including meter technicians, substation technicians, lineworkers, and stock room clerks, to install, monitor, and maintain the AMI infrastructure.

In addition to the benefits above, the union collective bargaining agreements reflect opportunities for training and apprenticeship in positions. For example, agreements establish wages for Apprentice Lineworkers and Apprentice Substation Technicians, and prescribe a path of progression for training positions through multiple stages of classification (i.e., from Apprentice to First Class), each affording a higher wage. Progression is predicated upon completion of approved training programs.

The following types of jobs are expected to be needed with the continued deployment of the ESMP. The timing and quantity of the positions required is not known at this time. The Company

[61] Economic and Health Impacts Report A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study December 2020 https://www.mass.gov/doc/economics-and-health-impacts-report/download Figure 7, Page 14

[62] Commonwealth's Clean Energy Climate Plan to 2050 https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050 , Figure 8-3, Page 139

will diligently and conservatively approve new positions in an attempt to mitigate the cost impact on ratepayers.

Construction (i.e. line workers, substation workers) - The Company expects system improvement projects identified in the plan will be constructed and operated by union workforce. These workers are expected to have the same skillset as our current line and substation workers. However, the quantity of projects and equipment installed in the field is likely to require an increase in the workforce.

Communications (i.e. field technicians) - Establishing the communication systems that forms the backbone of the advanced electric system requires the installation, monitoring, and maintenance of equipment such as antennas, modems, power supplies, and repeaters. These are new technologies involving new work practices, which will require that current union employees oe trained in new skills (e.g., moving antennas and power supplies on poles) and that new union employees be hired to conduct work on an ongoing basis. The Company expects that the diversity of new skill requirements will result in the creation of a new positions and associated union classification. These union workers tend to reside in the local vicinity to the service territory. Because these union positions are local, the barrier of transportation is minimized for local applicants.

Design (i.e. engineers, technicians, drafters, GIS workers) - The design of the projects proposed under this plan is completed predominantly with internal engineering staff. The lead engineering staff is typically highly technical staff with college degrees and many years of experience. The engineers leading the project typical have engineers with less experience working closely with them. This on-the-job style training allows the lesser experienced engineers the ability to shadow a more experienced engineering in a mentorship role. The engineers will also oversee technicians and drafters who help with the design and documentation process. These individuals have varying levels of education (i.e. high school diploma through college degree).

Operational and engineering staff attend industry conferences and seminars to understand the newest technology within the industry and how that technology can be deployed to benefit our customers. The Company also sends its employees to vendor specific training on new equipment to ensure safe and reliable installation and operation.

Engineering staff will need to extend their training and knowledge to the design and troubleshooting of communications equipment (radios, routers, modems, antenna, etc.) and controls. In addition, technical staff will need to be trained on the increasing complexity of relay schemes, FLISR, and systems integration to share data across systems.

Community Outreach – Community outreach will be an important aspect during the execution of the ESMP. See Section 3. The individuals conducting this outreach will be focused on developing relationships within the communities and acting as a conduit to educate the community on the system needs while gathering feedback from the communities and ensuring those comments and concerns are addressed within the final project designs. These individuals generally have college level degrees.

The Company takes a holistic approach to talent recruitment. The Company believes that any applicant that demonstrates the aptitude to learn can be mentored on the specific requirements of the job. The Company is also engaged at the colleges and universities level serving as members of the industry advisory councils. These industry advisory councils work to ensure that students coming out of universities and colleges have the tools and stills required to be successful. This work has proven successful in identifying potential employment candidates.

12.3 WORKFORCE TRAINING (WITH ACTION PLANS) – BARRIERS FOR BUILDING THE WORKFORCE NEEDED TO BUILD AND OPERATE THE GRID OF THE FUTURE

There are barriers to entering a new industry or new line of work and the energy industry is no different. The modern electric system requires an influx of new employees to be successful. Barriers such as awareness, diversity, equity, inclusion, language, proximity and transportation must be addressed in order to attract and train a new set of employees.

<u>Awareness</u> - Awareness may be the largest hurdle to identifying new employees. If an individual is not aware of the types of jobs within the energy industry, the probability of that individual seeking employment within the industry is low. Individuals who lack basic information about the energy industry early in their career may be less likely to search for a job in the energy industry.

The Company uses a broad range of multi-media to reach customers and prospective employees. Employee “word of mouth” referrals are generally highly effective at identifying prospective employees. A prospective employee is likely to take the recommendation of someone they know with first-hand knowledge of the Company. If the employees are happy with their positions, receive fair compensation and benefits, have the potential for training and advancement, their experience will resonate with individuals they know and trust.

The Company uses social media channels to reach our customers and prospective employees. Social media has shown to be an effective means to reach a larger audience. The Company proactively posts about job openings, career fairs, community events, interesting stories and other community events.

The Company works with local colleges and universities as members of their industry advisory boards to help provide guidance on curriculum and accreditation. This opportunity allows the Company to guide the colleges to develop courses that will provide the skills required to be successful in the energy industry. The Company supports those individuals who wish to expand their education through education reimbursement programs.

The Company works closely with the local colleges and universities to complete internship programs. Internship programs can be with any group in the company, but typically tend to be in the technical and sustainability parts of the Company. The internship consists of an overall introduction into the Company followed by projects of increasing difficulty all under the mentorship and training of more experienced staff. Interns are welcomed back to the Company for subsequent terms during their college career in the hopes that the intern will be hired upon graduation.

<u>Diversity, Equity and Inclusion Barriers</u> - The Company is an equal opportunity employer with a focus on diversity, equity and inclusion for individuals historically underrepresented in the industry, including women, people of color, and people who speak English as a second language. Our commitment to employee engagement is at the center of our core philosophies and is guided by our RISE values: Respect, Integrity, Stewardship, and Excellence. Through ongoing diversity, equity, and inclusion training and leveraging new recruiting channels, we are working to maintain and advance a culture that embraces diversity, promotes inclusion and attracts and retains employees from a broad spectrum of backgrounds and experiences. We believe we are a stronger organization when all voices and perspectives are equally represented. Recruiting from a diverse talent pool of qualified candidates to attract and retain top industry talent and maintaining an inclusive work environment ensures 'TeamUnitil' is a shared reality for everyone.

The strategy is to improve diversity through expanded recruitment and partnerships while fostering retention and employee growth by building Diversity, Equity and Inclusion ("DEI") awareness and competency, improving culture and relationships, and demonstrating commitment. To support ongoing efforts to create a healthy, productive environment for our employees, we formed a Diversity, Equity and Inclusion Council (DEI Council), a 15-member group tasked with ensuring these important concepts are woven deeply into the fabric of our culture.

The DEI Council established a charter, furthered employee education events, contributed to our DEI strategy, and created an employee newsletter to celebrate and share our progress and commitment to DEI. To create a value feedback loop, the DEI Council established the first Employee Resource Group to focus specifically on the empowerment of women in the utilities industry. We demonstrate our commitment to DEI through the expansion of recruitment channels to specifically target veterans, women, and members of the LGBTQ+ community, among others. The vigilant monitoring of equitable hiring practices will ensure we remain competitive within our industry and market.

Our DEI Council has engaged New England-based Mars Hill Group to assist in educating our employees about diversity. The Mars Hill Group conducts multiple learning sessions for all employees focused on diversity awareness in the workplace. The Mars Hill group also works hand-in-hand with the DEI Council to create a charter and action plan to define goals and facilitate our diversity initiatives. The Mars Hill Group conducts well-attended unconscious bias in-person training sessions for all employees.

As described in the comments of the Undersecretary of Environment Justice and Equity, "As the clean energy economy grows, electric distribution companies should ensure their workforce is inclusive of Black, Brown, Immigrant, Indigenous and low-income residents. As we grow the workforce needed to electrify the grid, EJ populations must have access to good paying and stable jobs. This includes creating a permanent pathway for residents who currently work in fossil fuel industries so they can transition to new clean energy jobs, as well as a pathway for the younger generations and those who have historically not had access to energy sector jobs."[63] These comments align with our approach to diversity, equity and inclusion within our company and within the community.

<u>Language Barrier</u> - The Company's service territory is predominantly English speaking, however Spanish and Portuguese are commonly spoken as well. Since the Company's service territory is relatively small and many of our employees live within the service territory, the Company currently has employees who speak Spanish and Portuguese. Therefore, the Company does not believe that language would be a barrier to new employees but offers training and assistance where required to ensure success within the Company.

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[63] August 14, 2023 comments from the Undersecretary of Environment Justice and Equity to the Grid Modernization Advisory Council.

Proximity and Transportation Barriers – Prospective employees who may be from disadvantaged backgrounds or communities may have a barrier to employment due to their proximity to the work location or their ability to get transportation to and from the office. Many people tend to look for employment within their immediate vicinity due to the inability to relocate to find employment. Since the Company's service territory is relatively small and many of our employees live within the service territory, transportation also does not tend to be an issue due to the relatively small footprint of the territory.

Training Barriers – The Company is constantly working to increase the quantity and access to training for our employees and prospective employees. The Company encourages individuals of all backgrounds to apply. Those employees who are a good fit but may not have the necessary education, training or experience are provided with the opportunity to increase their education through tuition reimbursement, their skills through paid training and their experience through on-the-job training opportunities under the close guidance of a mentor. The Company looks for opportunities to work with schools, vocational centers, apprentice programs, and other programs with a particular focus on providing a just transition of the workforce providing opportunities for historically underrepresented communities who may not have otherwise had the opportunity.

The Company recognizes that there is an opportunity to provide training opportunities to workers seeking to transition their experience to the clean energy sector. The Company has both gas and electric workers and will identify and implement training opportunities where appropriate to allow employees to transition their skills from the gas to the electric side of the business.

12.4 LOCATIONAL ECONOMIC DEVELOPMENT IMPACTS

To estimate the economic benefits attributable to the EDCs' respective ESMPs, the EDCs have collaboratively employed the Regional Input-Output Modeling System II (RIMS-II),[64] a tool developed by BEA. This approach leverages a region-specific capital multiplier for Massachusetts, ensuring a tailored evaluation of the economic impact. The EDCs' joint effort in this analysis underscores a commitment to understanding and maximizing the positive economic effects of

[64] "*RIMS II Input-Output Model User Guide*." Bureau of Economic Analysis,
https://www.bea.gov/sites/default/files/methodologies/RIMSII_User_Guide.pdf

their investments across the Commonwealth, reinforcing the collaborative approach in driving regional economic development.

The RIMS-II model serves as a state-of-the-art framework to estimate the economic benefits of capital investments, such as building new facilities or upgrading existing infrastructure. The analysis considers the direct and indirect impacts of such an investment. Direct impacts refer to the immediate economic activities associated with the capital investment, such as direct hiring of construction workers, purchasing materials, etc. Indirect impacts consist of the secondary economic effects that occur in other industries because of the direct capital investment, such as increases business for companies supplying construction materials, or transportation and logistics to deliver materials.

In particular, RIMS-II helps assess the direct and indirect “ripple” effects that such investments have on local job creation and overall economic activity. This model quantifies these impacts using "final-demand multipliers" -- key indicators that measure how each dollar of capital investment stimulates additional economic activity and job creation across various sectors of the local economy. This model helps depict that the proposed ESMP investments are not only advancing the utility's capabilities and the Commonwealth’s climate goals, but also contributing positively to the economic vitality of the Commonwealth.

The economic impact calculation was based on regional economy-wide impacts of the BEA RIMS-II approach and is summarized in the table below for the 5-year, and 10-year Capital Plans. Refer to 7.1 – Investment Summary Five-Year Chart and 7.2 – Investment Summary Ten-Year Chart in Section 7 for details on these investments.

Economic and Employment Impacts of ESMP Investments based on RIMS II Methodology		
ESMP Capital Plan Expenditure	**Total Investment**	**ESMP Investment**
5-Year Capital Plan ($M, 2025-2029)	$ 133	$ 50
10-Year Capital Plan ($M, 2025-2034)	$ 242	$ 66
Additional Economic Impact of Investment	**From Total Investments**	**From ESMP Investments**
5-Year Net Economic Benefit ($M, 2025-2029)	$ 32	$ 12
10-Year Net Economic Benefit ($M, 2025-2034)	$ 59	$ 16
Employment Impact of Investment	**From Total Investments**	**From ESMP Investments**
5-Year Employment Impact (2025-2029)	255	96
10-Year Employment Impact (2025-2034)	465	127

Table 76 – Economic and Employment Impacts of ESMP Investments based on RIMS II Methodology

To clarify the chart above:

- **Total Investments** include the capital investments in the base capital budget, plus previously approved capital spending for grid modernization in D.P.U. 21-82 and electric vehicles in D.P.U. 21-92.
- **ESMP Investments** include are the incremental capital investments proposed as part of this ESMP that are not otherwise included in the base capital budget nor previously approved by the Department.

The RIMS-II economic analysis uses the "Type I Final Demand Output Multiplier" to estimate the total economic impact of increased investment on the output of a region. For the ESMP, the Company leveraged the State of Massachusetts Type 1 multiplier for the Electric Power Generation, Transmission, and Distribution sector. This multiplier means that every dollar of direct capital investment produces an additional $1.244 of economic activity, including direct and indirect impacts of the investment. Applying the RIMS-II modeling to the total ESMP investments, as outlined in Section 7.1, shows that the Plan will contribute to considerable economic activity for the Commonwealth.

Over the span of 2025-2029, these economic benefits (nominal) are estimated at $32 million of additional economic activity generated by the Company’s Total Investment. When considering only ESMP Investments, the additional economic activity calculated is $12 million. Over the ten-year period of 2025 – 2034, the corresponding results are approximately $59 million from the Total Investments and nearly $16 million from ESMP Investment alone.

Additionally, the capital investments are expected to foster job creation across the state and through local industries. This includes direct jobs such as construction workers, and indirect jobs[65] such as local suppliers providing materials. Similar to the economic impact analysis, the RIMS-II model applies an indirect job multiplier of 1.920 for every additional $1 million of output delivered to final demand.[66]

The RIMS-II model estimates the Total Investments will generate 255 jobs[67] from 2025 to 2029, and more than 465 jobs during the extended period of 2025 to 2034. When considering solely the ESMP Investment during the same periods, job creation is expected to be 96 and 127, respectively. The estimated direct and indirect impacts of these calculations reflect a broad perspective of the impact of direct economic activity and the rounds of spending in the economy associated with these investments. This analysis does not try to estimate job losses as part of the analysis.

A key objective of this ESMP is the removal of barriers to the growth of Massachusetts' green economy. As a major clean energy infrastructure initiative delivering new technology and capabilities to over one million customers, the proposed ESMP will have a positive impact on the Commonwealth's green economy. In addition to benefits associated directly with the Company's plan, Unitil expects the creation of numerous other business opportunities across multiple industries. At the macroeconomic level, the types of indirect jobs created by transitioning to a green economy will include positions in the renewable energy, construction and installation, green investment, research and development, energy efficiency, education and training, consulting, and environmental services sectors.

The Company's service territory has a high percentage of customers who live in an Environmental Justice community or are identified as a low-to-moderate income household. The Company is keenly aware that the future of the electric system, if not implemented in a carefully thought out plan, can have a diverse impact on our customers and the communities we serve. Mitigating the

[65] Direct jobs are those created by the investment itself, while indirect jobs are in the businesses that support the investment.
[66] https://www.bea.gov/sites/default/files/methodologies/RIMSII_User_Guide.pdf
[67] Includes both full-time and part-time positions and are not equivalent to full-time equivalent (FTE) positions

potential adverse effects of a clean energy transition on our customers and communities and promotes the benefits and opportunities the transition can bring to our customers and communities. A just transition to a clean energy future will ensure the benefits of the clean energy transition are shared widely and support provided to those who stand to lose from the transition.

From a workforce benefit standpoint, technology is rapidly evolving resulting in increased technical and non-technical jobs and open up opportunity for training and growth within the workforce. These jobs are local to our service territories so residents within our communities will have a greater opportunity for employment. We are focused on providing the skills and knowledge needed to develop and train a workforce that supports the transition to a modern grid while returning economic benefits to the communities that we serve. An increase in the quantity of good paying, local jobs that are available to those residents of Environmental Justice communities can provide immediate financial benefits that may not otherwise be readily available.

12.5 HEALTH BENEFITS

The primary health benefits associated with this plan are focused around enabling the interconnection of renewable energy resources and optimizing system demand at all times of the year. These efforts will reduce GHG emissions created by burning fossil fuels. Electrification and the interconnection of clean energy resources will reduce exposure to harmful pollution. A reduction in GHG emissions will have a direct impact on improving air quality, result in less respiratory illness and prevent other health related conditions due to increased temperatures.

The electric system as an enabling platform strives to minimize GHG emissions by integrating greater renewable energy DER and empowering customer energy options. Technology advancements in monitoring and control of DERs will allow the interconnection and operation of a larger percentage of renewable energy resources than otherwise could have been supported. Demand reduction programs supported by advanced monitoring and control will lead to the replacement of inefficient end use devices.

VVO provides the opportunity for improved energy efficiency leading to decreases in demand and reduction in greenhouse gas emissions. In addition, the VVO system also enables the Company to manage customer power quality better and allows for a greater penetration of renewable DERs on the system and lead to a further reduction in GHG emissions.

AMI provides the data and tools necessary to drive a reduction of electricity usages and peak load reduction. The information provided by AMI gives customers the opportunity to take more control over their energy usage leading to reduced emissions. AMI supports reduced overall energy usage through VVO and energy management systems. AMI helps to reduce peak demand by supporting dynamic pricing (such as TOU or TVR), energy management and smart appliances. AMI reduces emissions by eliminating the transportation required for meter reading fleets.

Integrating DERs and other renewable resources into the distribution system is key to an environmentally friendly distribution system. AMI provides the information necessary to match actual load usage curves with the potential DERs supporting the load. In addition, AMI supports demand side management programs which reduces distribution and transmission peaks resulting in lower peak loads, reduces emissions and reduces the need for non-environmentally friendly generation resources.

As part of the net benefits analysis described in section 7.1.4, the Company has quantified the estimated CO2, NOx and PM2.5 emissions enabled by this plan.

Quantified Outcomes Driving Monetized Net Benefits	TOTAL
Total MT CO2 Reduced	439K MT
Total MT NOx Reduced	80 MT
Total MT PM 2.5 Reduced	2 MT

Table 77 – Projected Emission Reductions Enabled

Technology improvements in roof top solar continues to drive the price point lower and lower. The costs of other DERs such as energy storage and energy efficiency improvements are also experiencing decreasing pricing and increased sales. Demand response opportunities continue to grow as home assets such as HVAC, water heaters, LED lights, thermostats and even electric vehicles as the ability to control these assets from the internet become more prevalent.

A sustainable and environmentally friendly electric distribution system requires effective and efficient use of electricity. Customers who have knowledge, tools and technology can support the overall goals of energy conservation during peak load hours leading to reduced emissions. Customers who are engaged and have a clear understanding of their individual situations have a greater tendency to make beneficial changes.

13 CONCLUSION

The Plan is designed to detail the Company's actions to proactively upgrade its distribution (and transmission system where applicable) to: (i) improve reliability and resiliency; (ii) increase the timely adoption of renewable energy resources; (iii) promote energy storage and electrification technologies; (iv) prepare for future climate-driven impacts on the electric system; (v) accommodate increased electrification from transportation, building and other potential demands; (vi) minimize or mitigate the impact to ratepayers while helping the commonwealth realize its greenhouse gas emission limits.

The Company has taken a measured approach to this Plan. Due to the Company's overall size, it cannot be all things to all people. We need to focus on the needs of our customers. This report is a living document designed to provide direction and guidance to address the goals listed above but maintain flexibility to alter the plan to address future challenges that have not yet been identified. The plan provides a 5-year forecast, 10-year forecast and a demand assessment through 2050 to account for future needs. This plan will continue to be updated and improved upon based upon feedback from stakeholders as well as changing future conditions. The Company looks forward to continued collaboration on the development and implementation of this Plan.

Substantial new utility investment is needed for the clean energy future and to ensure the Company's distribution system continues to be safe, reliable, and resilient. With the Department's approval of the Company's ESMP, along with timely and adequate recovery of ESMP investments, the Company can work together with the Commonwealth to enable reaching its clean energy and decarbonization goals.

The Company's load forecast shows that the 2050 system peak load will be approximately 3.5 times the 2025 forecasted load. This never before seen increase in load is the result of a merger of energy shipments from natural gas and liquid fuels and their associated infrastructure, into the electric power grid, a challenge the system was not designed to handle.

In addition, the Commonwealth's goals articulate aggressive solar targets of 23 GW across the state (scaled to approximately 60 MW for the Company's system), a number that rivals today's ISO-NE's System Peak, as distributed generation. This generation, due to its extensive land requirements, is deploying in rural regions which serve neither high loads nor have anywhere near the capacity required.

The exiting electric system is designed with an adequate amount of electrification and DER hosting capacity to ensure the safe and reliable operation of the system in the short term. The Commonwealth's goals propose a step change in the adoption of electrification technologies (electric vehicles and heat pumps) and DER integrations. If the Commonwealth's goals are realized, it will drive the need to significantly expand the capacity of the system to serve the new loads and DERs.

The Company's service territory has a high percentage of customers who live in an Environmental Justice community or are identified as a low-to-moderate income household. The Company is keenly aware that the future of the electric system, if not implemented in a carefully thought out plan, can have a diverse impact on our customers and the communities we serve. Mitigating the potential adverse effects of a clean energy transition on our customers and communities and promotes the benefits and opportunities the transition can bring to our customers and communities. A just transition to a clean energy future will ensure the benefits of the clean energy transition are shared widely and support provided to those who stand to lose from the transition.

The Company is mindful that affordability is a major concern for all customers and communities, and the Company will continue to support efforts to ensure that cost impacts are correlated with the benefits that accrue from improved reliability, resiliency, and clean energy investments. In addition to low-income discounts, arrearage management plans, and other customer cost saving programs the Company has implemented, the Company's energy efficiency program is essential to reducing energy usage and therefore costs to customers.

The Company has taken a practical approach to developing its ESMP. This ESMP is designed to support the Commonwealth clean energy goals while providing customers with overall benefits that outweigh the costs. The 5-year plan includes $133 million to capital investment, of which approximately $50 million is incremental ESMP investments. The incremental investments result in approximately 0.2% to 0.4% increase in bills depending on the rate class. Unitil looks forward to participating in the Department's newly opened inquiry to examine energy burdens with a focus on energy affordability for residential ratepayers (D.P.U. 24-15) and any future rate redesign docket opened by the Department.

The Company has proposed an approach to working with the EJ and underserved communities throughout the deployment of this ESMP plan to address their concerns and develop an equitable process for all. The Company has developed an ESMP specific Equity Framework A (see Section 3), that it will continue to utilize throughout this and future ESMP planning, outreach and implementation processes. Although substantial investments are needed for this transition, the long-term benefits exceed the costs. The Company and the Commonwealth should be focused on ensuring that disadvantaged customers and communities are benefiting from proactive investments and participating in the Commonwealth's policy energy vision. This may include ensuring there is funding for expanded assistance programs and low-income bill discount programs, and reforms that support the ability of customers in Environmental Justice populations, especially low-income customers, to participate in customer programs.

13.1 NEXT STEPS

The Company has worked collaboratively with the other EDCs, GMAC and other stakeholders to present the plan in a transparent manner. We will continue to work with the Department and stakeholders through the review during this docket, as well as any subsequent issues identified that cannot be completed during the short timeframe of this docket.

As the Company begins the implementation of this ESMP, it will work collaboratively with the CESAG to develop a community engagement framework to be applied to future ESMP proposed investment projects.

In compliance with the regulations set forth in Massachusetts General Laws Chapter 164 Section 92B – 92C effective August 11, 2022, the Company will file two reports per year (as described below), which will include a set of agreed upon metrics.

13.2 PROCESS TO SUPPORT UPDATES TO ESMP THROUGHOUT THE 5-YEAR CYCLE

The Climate Law, Section 92B (e) requires the EDCs to submit two reports per year to the Department and the Joint Committee on Telecommunications, Utilities, and Energy on the deployment of approved investments in accordance with any performance metrics included in the approved plans.

To ensure all ESMP reports are valuable, actionable and support transparency with the GMAC, stakeholders, regulators and policy makers, the EDCs support development of a common reporting template. At a minimum, the template would include provisions for the EDCs to report on progress in implementation, stakeholder engagement, and benefit realization. As described in Section 13.3, the EDCs also support adoption of common performance metrics. Results relative to these metrics would be included in ESMP reports.

The EDCs recommend bi-annual reporting as follows:

- April 1, for the prior year plan period providing a comprehensive report on ESMP progress, including results relative to performance metrics. (Replacing the current Grid Modernization Plan Annual Report.)
- October 1, for the six months of the current year, January through June, to provide a higher-level interim review of year-to-date progress.

This process would involve a review of the prior two bi-annual reports and an assessment and recommendation from the Company or joint EDC's regarding elements of the ESMP or specific investments. The EDCs expectation is that this review cycle will help to refine and improve the ESMP and the ability to move forward in supporting the state's clean energy future in a cost effective and efficient manner.

13.3 REPORTING AND METRICS REQUIREMENTS WITH COMMON EDC TABLE

The EDCs support the creation of metrics to measure progress and performance of the ESMP investments in relation to the ESMP objectives. The EDCs are performance-focused and aspire to provide safe, reliable, and cost-effective service to all customers every single day. Consistent reporting and metric measures for the ESMP will provide transparency into the performance on the approved ESMPs and provide opportunities to adjust for improvements as the plans are implemented.

The EDCs note that they have already committed to metrics in other areas and there are many filed and publicly available metrics across several open or active dockets at the Department. There are several existing frameworks and reporting constructs that should initially be considered and leveraged for any suitable and transferable metrics.

The EDCs have reviewed the metrics that are currently approved or are in process of consideration by the Department and have classified those investment categories that we consider to be applicable to the ESMP and those that are not applicable to the ESMP.

The following investment categories have existing or pending metrics that are directly applicable to the ESMP objectives. Metrics existing or proposed in these areas could be incorporated into the ESMP reporting template with necessary revisions.

- Grid Modernization
- AMI
- Electric Vehicles
- AMI / Time Varying Rates
- Interconnection TEM

The following investment categories have existing or pending metrics that are not applicable to the ESMP given that they are either, specific to an EDC, have a separate existing stakeholder process in place, or are not directly applicable to the ESMP objectives.

- Energy Efficiency
- CIP
- Service Quality
- Rate Case

The EDCs view the existing set of metrics as an optimum starting point to develop the overall comprehensive set of metrics to measure ESMP investments and outcomes in relation to the ESMP objectives. This starting point can be supplemented with additional metrics that track the ESMPs implementation once approved by the Department.

The 2022 Climate Act requires an extensive amount of information to be included in an ESMP, but limits the Department's review to seven months from the date an ESMP is filed. Moreover, each EDC is required to submit their ESMP on the same date, further complicating the Department's review of these comprehensive plans in such a limited timeframe. In addition, the 2022 Climate Act, contemplates consideration by the Department of several issues that, standing alone, might require far longer than seven months to review. As such, the review of metrics, even if able to be completed by the EDCs in time for consideration by the Department in the present ESMP dockets, would be very difficult to review and adjudicate in the time period allowed by statute.

The EDCs propose to deliver both infrastructure and performance metrics, which will include both statewide as well as company-specific metrics, tied to each Company's ESMP goals. Infrastructure metrics track the implementation of approved technologies and systems, and performance metrics measure progress towards the ESMP outcomes. In developing metrics associated with each goal and outcome as this proceeding moves forward, it is imperative that such metrics follow the following principles:

1. be susceptible to objective and transparent measurement;
2. have an established baseline against which performance can be measured;
3. measure "performance" that is actually within the EDC's control; and
4. must also consider whether there are conditions precedent for any metrics that need to be factored into their use or measurement. Metrics that lack these foundational elements could result in unintended consequences of penalizing a utility for performance that is not actually substandard, nor a product of the utility's own efforts.

Additional areas of consideration for creating metrics include:

- Legislative compliance – meet the expectations laid out in the Climate Act;
- State Goals and Policy Delivery – focus on achievement of State policy goals;
- Customer Value – creates/demonstrates value for customers, balancing the burden across our customer demographics;
- Inter-Metric Consistency – consider performance metrics holistically, avoiding a metrics paradox, where achievement of one metric necessarily means giving up or failing on others.

The EDCs developed an initial view of both the statewide and company-specific metrics, which the EDCs provided to the GMAC in October 2023. The purpose of these ESMP metrics is to record and report information, internally to the Department, to GMAC, and to the Telecommunications, Utilities, and Energy working group.

Category	Description
Implementation	Using commercially reasonable efforts, the achievement dates of ready for load (RFL) for major ESMP infrastructure projects which will be measured from the time the EDC receives: (1) a final, non-appealable order from the Department approving a cost recovery mechanism applicable to the project; and (2) all required permits and approvals for such projects through final, non-appealable state or federal orders and local permits
Resiliency	The percentage of customers covered by/benefiting from incremental resiliency investments outlined in the EDC's ESMP.
Electrification and DER Hosting Capacity	The increase in: (a) DER hosting capacity, and (b) load serving capacity by substation demonstrated by an increase in transformer rating installed. This metric will additionally include reporting information specific to Environmental Justice Communities (EJCs), stating what percentage of benefits is located in an EJC. This metric will be measured from the time the EDC receives: (1) a final non-appealable order from the Department approving a cost recovery mechanism applicable to the substation project, and (2) for

	specific projects at the time when all required permits and approvals for such projects are received, including through final, non-appealable state or federal orders and local permitting processes.
Greenhouse Gas Reduction	A measure of the greenhouse gas reduction impact of investments enabled in alignment with statewide greenhouse gas reduction targets. This metric will be measured from the time the EDC receives: (1) a final non-appealable order from the Department approving a cost recovery mechanism applicable to the investment, and (2) for specific projects at the time when all required permits and approvals for such investments are received, including through final, non-appealable state or federal orders and local permitting processes. The EDCs have contracted with an expert consultant to analyze the net benefits of each EDC's incremental investments, which will include greenhouse gas reduction analyses. The EDCs welcome input from the GMAC regarding recommended approaches to analyzing and measuring greenhouse gas reduction benefits.
Use of DER as a Grid Asset	For the EDC's distributed energy resources management system (DERMS), (a) the number of participating sites, (b) the amount (kW) of non-company owned dispatchable assets that the utility can control, and (c) number of instances sites are dispatched. The EDCs note that this metric is already under consideration by the Department as a proposal through 2025 in D.P.U. 21-80, D.P.U. 21-81, and D.P.U. 21-82. The EDCs propose that the metric would continue for incremental DERMS investments in 2026 and beyond.
Stakeholder Outreach	• The number of outreach and involvement meetings about the respective EDC's ESMP filing with stakeholders, including EJCs, municipal leaders, community-based organizations and customers (i.e., residential, commercial and industrial, as well as DER customers). • The number of outreach and involvement meetings about specific ESMP infrastructure projects with stakeholders, including EJCs, municipal leaders, community-based

	organizations, and customers (i.e., residential, commercial and industrial, as well as DER customers). • The number and category of requests made as part of stakeholder feedback on specific ESMP infrastructure projects, classified into visual mitigation, access accommodations, work hours, right-of-way maintenance, informational accommodations, engineering accommodations, and damage prevention, as well as the EDC's response to these requests classified as under consideration, implemented, not accepted with reason, and other.

Table 78 – Potential Metric Categories

The EDCs will propose additional performance metrics to track the benefits resulting from the Company's ESMP implementation. Examples of performance metrics include those that measure achievement of specific proposed outcomes, such as energy and demand savings resulting from CVR/VVO.

The EDCs propose to work with interested stakeholders to address metrics relating to the EDCs' respective ESMP investments in a future phase of the ESMP dockets.

13.4 PROCESS TO REPORT TO DPU AND JOINT COMMITTEE ON TELECOM, UTILITIES AND ENERGY

The EDCs expect an ongoing collaboration with the Grid Modernization Advisory Committee throughout the ESMP plan period with discussion and updates supported through the bi-annual reporting. In addition to the GMAC, the bi-annual reports will be provided to the Joint Committee on Telecommunications, Utilities, and Energy. As described in Section 13.2, the EDCs believe the proper timeframe for the bi-annual reporting would be April 1 for the July – Dec timeframe and October 1 for the Jan-Jun timeframe. These timelines best align with many existing dockets and annual reporting timelines which will be leveraged and incorporated into our overall bi-annual reporting efforts.