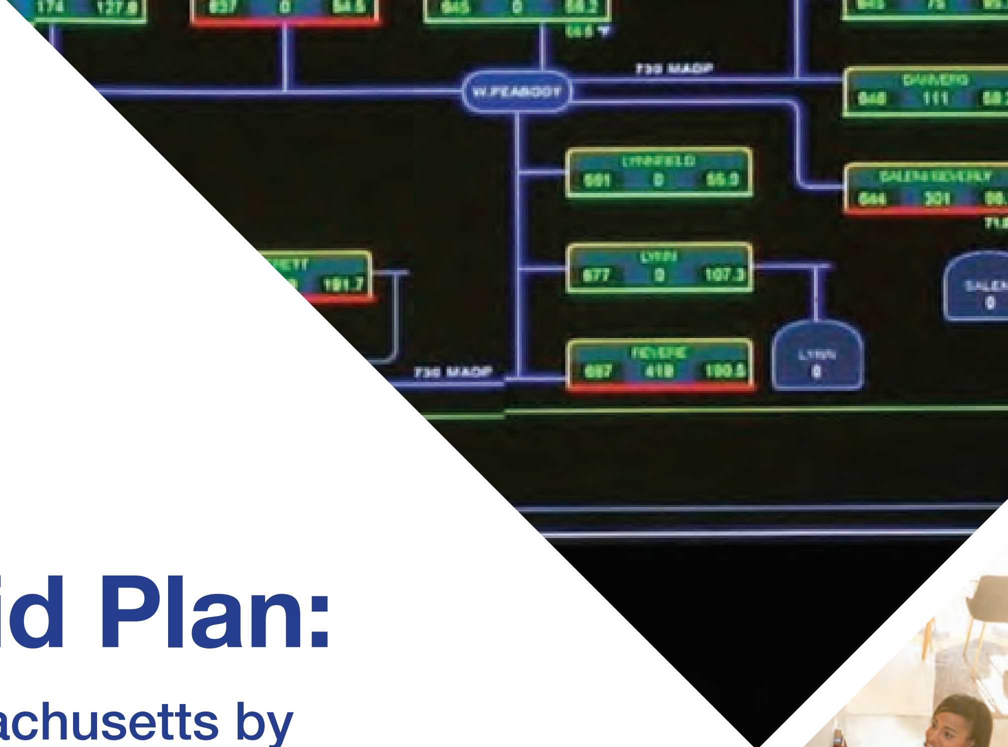


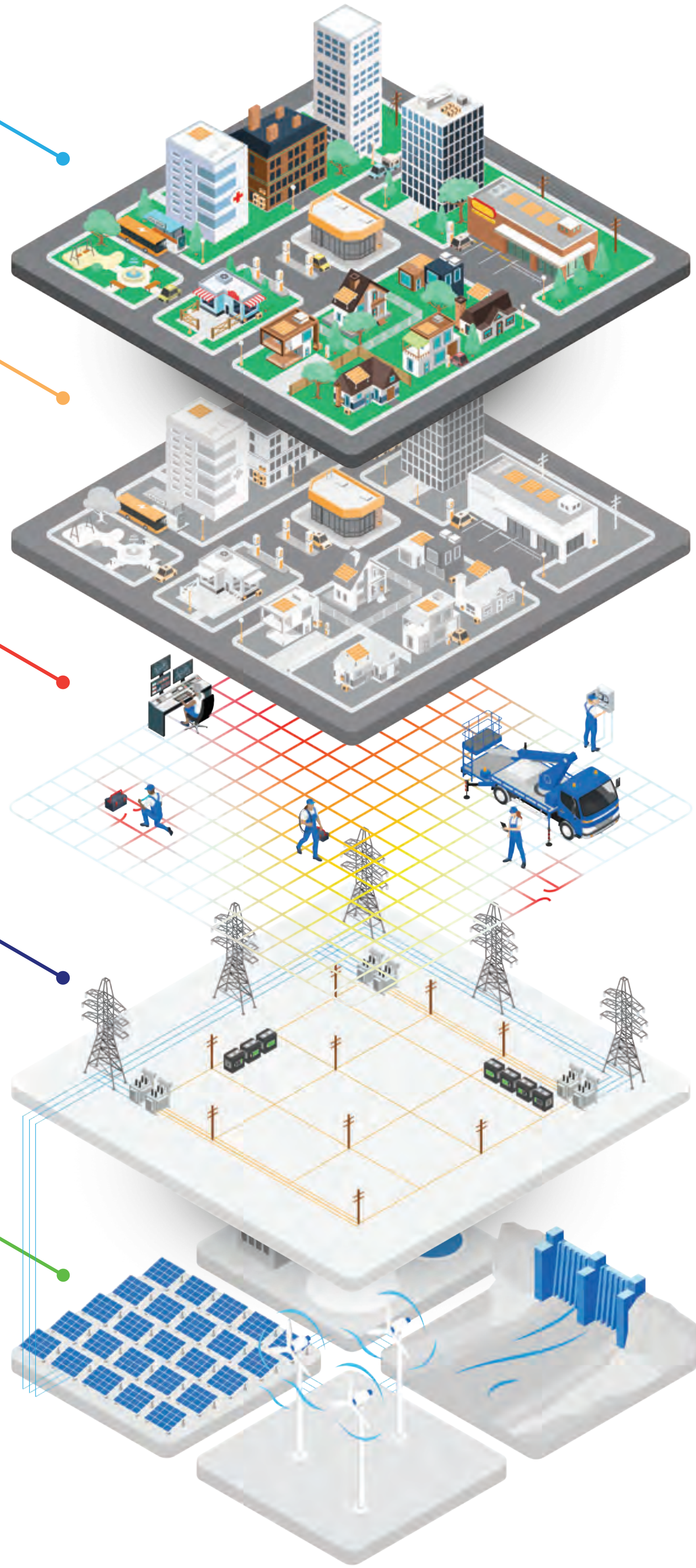
nationalgrid

Future Grid Plan:

Empowering Massachusetts by Building a Smarter, Stronger, Cleaner and More Equitable Energy Future

September 2023

Building Tomorrow's Energy System



A Smarter, Stronger, Cleaner, More Equitable Energy Future

A network that supports the Commonwealth's climate, clean energy, and equity goals and delivers the fair, affordable, and clean energy transition for all our customers and communities.

Customer Programs

Provide customers with information, products, and services to enable clean energy, efficiency, and demand management options so they can make the energy choices that work for them, when they want them.

Technology and Platforms

Create a smart, flexible, and dynamic grid that can manage the future supply mix, energy needs, and leverages distributed resources with real-time communications to solve grid problems and provide grid resiliency.

Network Investments

Build a strong network that is one step ahead of customer needs, ready to respond to developer requests, and is reliable, resilient, and secure, regardless of weather or evolving threats.

Connecting our Customers to Renewables

Enable and connect our customers to the increased renewable generation on the grid – wind, solar, hydro, geothermal, and storage.

The investments proposed in this Future Grid Plan will empower our customers and communities throughout Massachusetts by building a smarter, stronger, cleaner, and more equitable energy future.

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A message from our leadership

Steve Woerner
NE President

Nicola Medalova
Chief Operating Officer, NE Electric

Every day at National Grid, our more than 6,500 team members work together to build a smarter, stronger, cleaner, and more equitable energy future for our customers and communities in more than 240 towns and cities across 5,900 square miles.[1]

We know what we do matters immensely, and how we do it matters even more.

A smarter and more intelligent system can provide customers with more options and the ability to make clean energy decisions that work for them. A stronger system will be one that is more robust, better able to withstand the impacts of climate change, and protect against evolving threats. And, a cleaner system can connect more renewable resources, energy storage, and electrified transportation and heating more quickly at all levels and leverage these resources to create value for the grid and customers.

We are at an inflection point. To meet the Commonwealth's ambitious climate change and clean energy goals – goals that we share – we must begin building this future now. And, we know that we cannot build it alone and that we don't have all the answers. Massachusetts is a state known for solving big problems and delivering big results. It is a state with an innovation ecosystem and is focused on equity that drives collaboration, partnership, and new ways of thinking. We will need to harness this innovative and collaborative spirit to achieve the energy future that works for all.

By developing and submitting this Future Grid proposal as our Electric Sector Modernization Plan, we are taking a first step toward defining the scope and scale of what we collectively must do over the next 25 years to combat climate change and enable a more electrified future. We are doing this by identifying the system investments and changes needed in the electric distribution system, engaging broadly to stimulate ideas, and encouraging input to ensure this proposal is responsive to and supportive of the needs and expectations of our all customers and communities.

We have an opportunity to make real and lasting change. And, while we are building and preparing the grid and our broader energy system for the future, we remain focused on what is right in front of us. Our customers expect and deserve great service and safe, reliable and affordable energy today, which we will continue to deliver.

We are committed to empowering Massachusetts by building a smarter, stronger, cleaner, and more equitable energy future. And we are excited to share our Plan to do that and truly look forward to being a partner for progress in all our communities across the Commonwealth.

Stephen J. Woerner

Steve Woerner
NE President

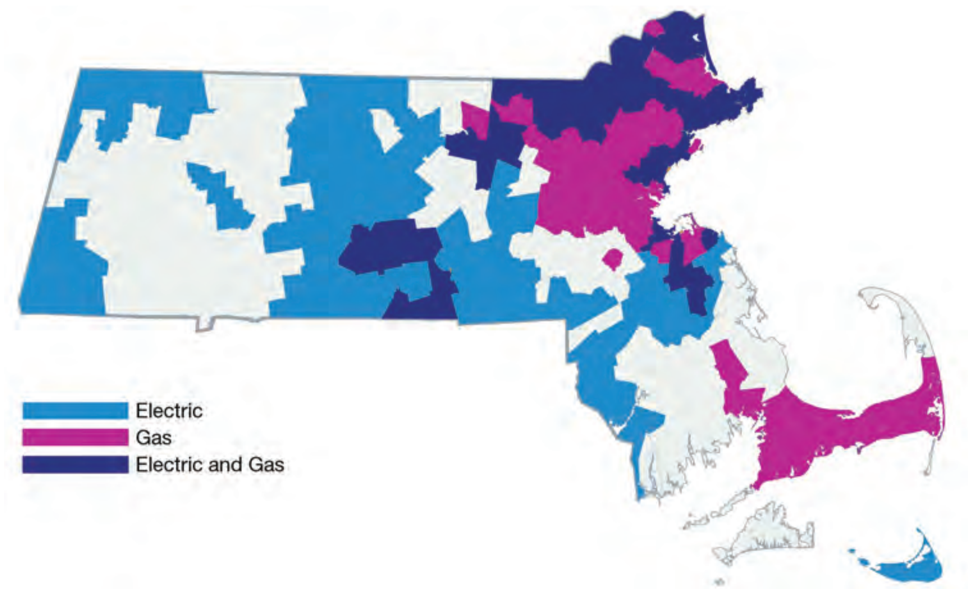
Nicola Medalova

Nicola Medalova
Chief Operating Officer, NE Electric

[1] Refers to both National Grid's Massachusetts' electricity and gas services.

About us

We’re taking action to achieve net zero and to deliver a fair, affordable and clean energy future to **2.3 million customers in** more than **240 towns and cities...**



...by our teams...

~6,500 Employees	**~3,300** Employees represented by 15 unions

...while supporting our communities...

13K+ hours of employee volunteerism	**$4M+** in charitable contributions

Serving our 1.3M electric customers via our networks...

18K
Miles of electric distribution lines

178
Distribution substations

720K
Poles

...and by making customer connections.

200 MW
Total DER connected in 2022

~1,800
EV Chargers enabled to date

18K+
Households that installed heat pumps in 2022 through the Mass Save program, with 10k+ supported by National Grid

2GW
DER connected to our network

~32K
Additional EV Chargers to be enabled via Phase 3 EV programs

45K+
Planned additional households for heat pump installation through Mass Save by 2024, with 21k+ targeted for support by National Grid

1.0 Executive Summary

Overview

Massachusetts' ambitious 2050 Clean Energy and Climate Plan (CECP) establishes nation-leading goals and supports pathways to reduce climate pollution and reach net zero greenhouse gas emissions by 2050 – goals we share at National Grid. The CECP is an equity-centered plan rooted in decarbonizing the electricity consumed by all customers.

Today, the natural gas network in Massachusetts carries three times as much energy at peak as the electric network, mostly to meet heating needs, with delivered fuels, such as heating oil, also playing a critical role. At the same time, internal combustion vehicles represent almost all vehicles on the road and rely on an established and ubiquitous fueling network that took more than 100 years to build. Making this shift from a multi-fuel energy system to one primarily reliant on electricity will require a major grid build-out, which must start now.

Achieving the Commonwealth's climate, clean energy, and equity goals requires a comprehensive, thoughtful, and flexible plan to expand and upgrade today's electric grid at a significant pace and scale to enable increased electrification and move away from a fossil-based economy. To support this future, the electric grid must be fundamentally smarter, stronger, and cleaner in order to:

- Deliver necessary and timely emission reductions
- Be ready when customers need it, and be reliable and resilient, regardless of changing weather
- Enable the deployment and optimized use of new, electrified end-use technologies like heat pumps and electric vehicles and quickly connect distributed technologies like solar and battery storage
- Provide a more equitable, individualized, and seamless experience for all customers
- Drive innovation, economic opportunity, and growth, prioritizing communities that have historically been burdened and left behind by the fossil-based economy

Pathways to accomplishing the Commonwealth's net zero greenhouse gas emissions goals by 2050[2]

Transportation

97% of light-duty vehicles (5 million) electrified

93% of medium- and heavy-duty vehicles (over 350,000) electrified or non-emitting

Buildings

80% of homes (over 2.8 million) heated and cooled by electric heat pumps (including those with on-site fuel backups)

87% of commercial space heated by either electricity or alternative fuels

Electric Power

2.5-fold increase in electric load compared to 2020

97% of electricity consumed is from clean and renewable sources

Non-Energy and Industrial

52% of industrial energy use electrified

Jobs and Health Benefits

65K additional full-time jobs created from the clean energy transition

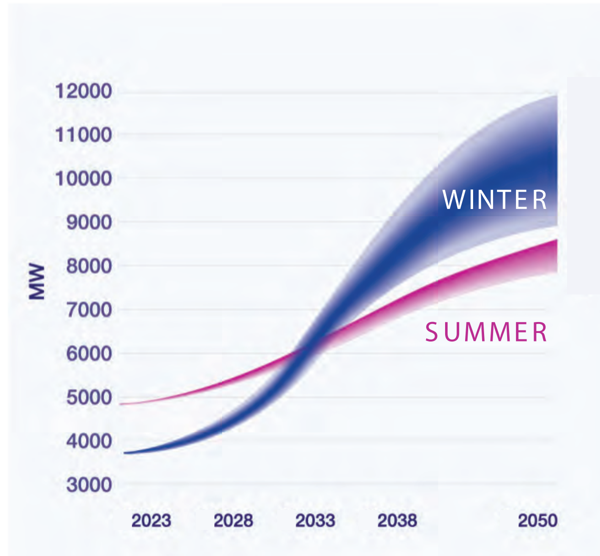
up to **$4.7B** in health benefits

[2] These are statewide goals from the Clean Energy and Climate Plan (CECP).

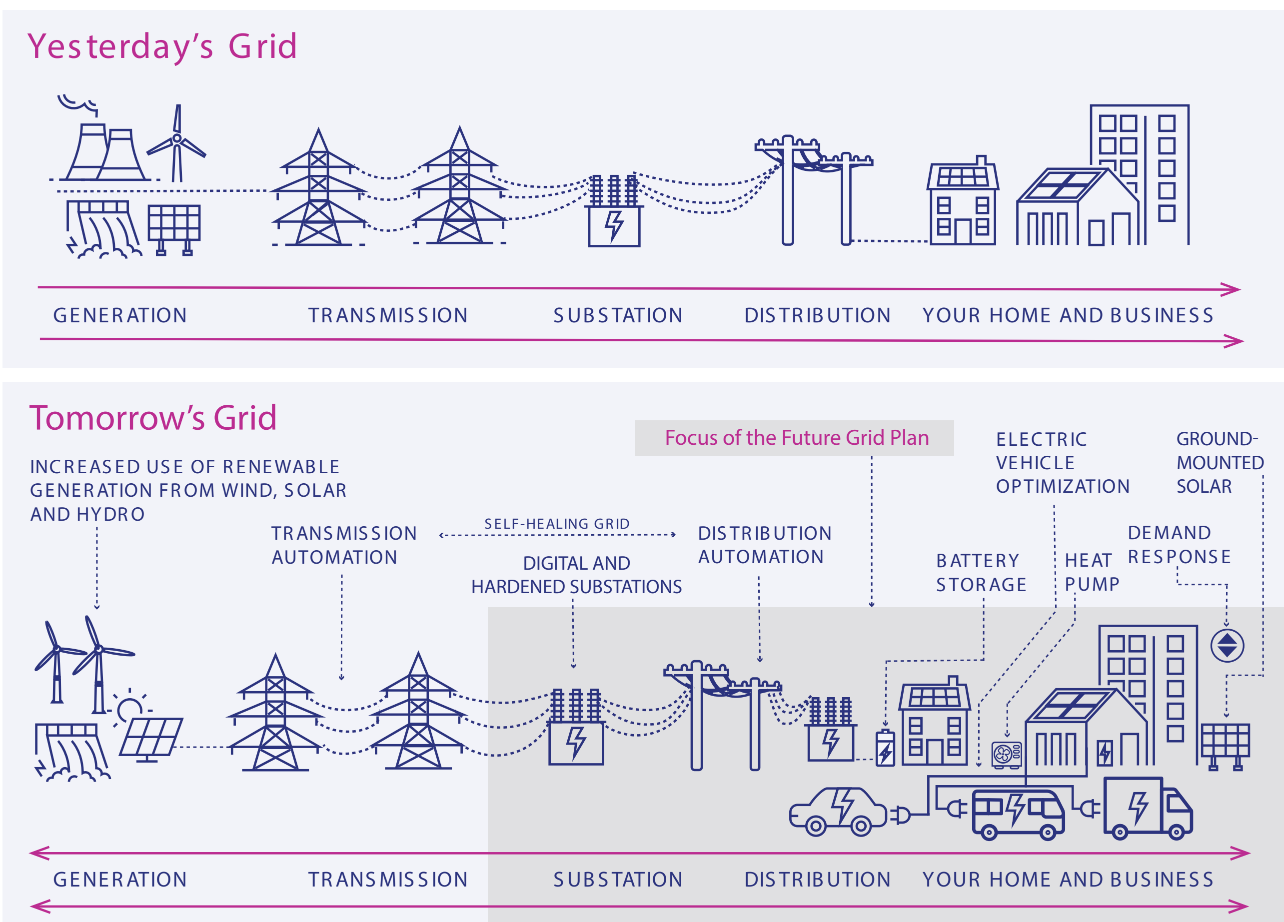
To meet Massachusetts' statewide goals by 2050, the grid of tomorrow must meet peak customer demand more than twice as high as today's, with the peak occurring in the winter as opposed to summer. It must also connect at least twice the amount of energy storage, 10 times the amount of renewable energy, 75 times the number of EVs, and 100 times the number of heat pumps than we see today.

The Company's Future Grid proposal will transform the distribution grid of the past into a smarter, more resilient two-way electricity superhighway that powers sustainable communities today and into the future and provides all customers the opportunity to participate in and benefit from the clean energy transition.

MECO's peak demand will more than double, and shift to the winter



The Commonwealth's Power Grid—Yesterday and Tomorrow



Massachusetts is a clean energy leader

The Commonwealth has already made significant strides towards enabling this clean energy future. Over the past decade, Massachusetts has achieved electric energy savings of more than 2% of total sales per year, saving customers billions of dollars, and avoiding thousands of tons of greenhouse gas emissions. We have gained over 4 gigawatts (GW) of solar power, enough to power 700,000 homes, more than any other state in New England. The Commonwealth has supported investments in local distribution grids, which has resulted in National Grid maintaining systemwide reliability at 99.9% for our customers and supported steps to modernize and prepare the grid for the impacts of climate change. And it did all this while also advancing energy equity and climate justice through policy, programs, and practice.

Much of this progress has been driven by legislation, including An Act Driving Clean Energy and Offshore Wind (Act), which was enacted in 2022. This Act directed each Massachusetts electric distribution company (EDC) to file an Electric Sector Modernization Plan (ESMP) that identifies "upgrades to the distribution system — and where applicable transmission system — needed to meet the Commonwealth's climate and clean energy goals over three planning horizons: 1) a 5-year forecast, 2) a 10-year forecast and 3) a demand assessment through 2050."

The Company's Future Grid proposal builds on the Commonwealth's earlier work

This Future Grid Plan (Plan) proposal serves as the Company's ESMP submission: it provides a roadmap for how the electric system will operate in the future while outlining the supporting investments needed over the next 25 years. This proposal builds on investments already underway to modernize the grid and complements the investments the Company continues to make to provide safe and reliable service to our 1.3 million electric customers throughout the Commonwealth, as adjudicated and approved in our periodic base rate reviews at the Department of Public Utilities (DPU).

The additional Plan investments, beyond those approved and planned today as part of our core investments, will be across all aspects of our distribution business — network infrastructure, technology and communications platforms, and customer programs — and all regions of the Commonwealth. To be successful, the Plan requires ongoing coordination with the Commonwealth, the state's other EDCs, and local gas distribution companies (LDCs) to integrate our energy planning efficiently and cost-effectively transition to a more electrified economy. It will also require policy changes to accelerate the build-out needed to support this clean energy future and ensure a just transition.

The Company's proposed Plan aligns with what we heard from customers and communities as part of our extensive engagement process, which included outreach to our National Grid Customer Council composed of residential and commercial customers, and to public officials, businesses, clean energy groups, nonprofits and community groups representing Environmental Justice Communities (EJCs).

The Future Grid Plan is rooted in a strategy that:

- Empowers customers to act by having more choice and more control
- Creates a ready, robust, and resilient energy system
- Leverages innovation, drives efficiency, and enables greater system flexibility
- Results in a more just and equitable energy future

The Company's Future Grid Plan achieves the Commonwealth's goals through investments to make the grid smarter, stronger, and cleaner

Over the next five years, the Company proposes to invest more than $2 billion through the Future Grid Plan to meet the Commonwealth's electric-based approach to achieving net zero emissions and enabling the just transition. This future is reliant on a grid that is smarter, stronger, and cleaner to enable expanded energy efficiency and demand response programs through, for example, Mass Save®, advance the smart electrification of transportation and heating, and connect and integrate renewables and storage, at all levels and in all communities.

In developing our proposed Plan, we established five key outcomes to ensure that these incremental investments were carefully scoped to meet specific needs, based on forecasted demand, known and anticipated system capacity and operational needs, and customer expectations and requirements.

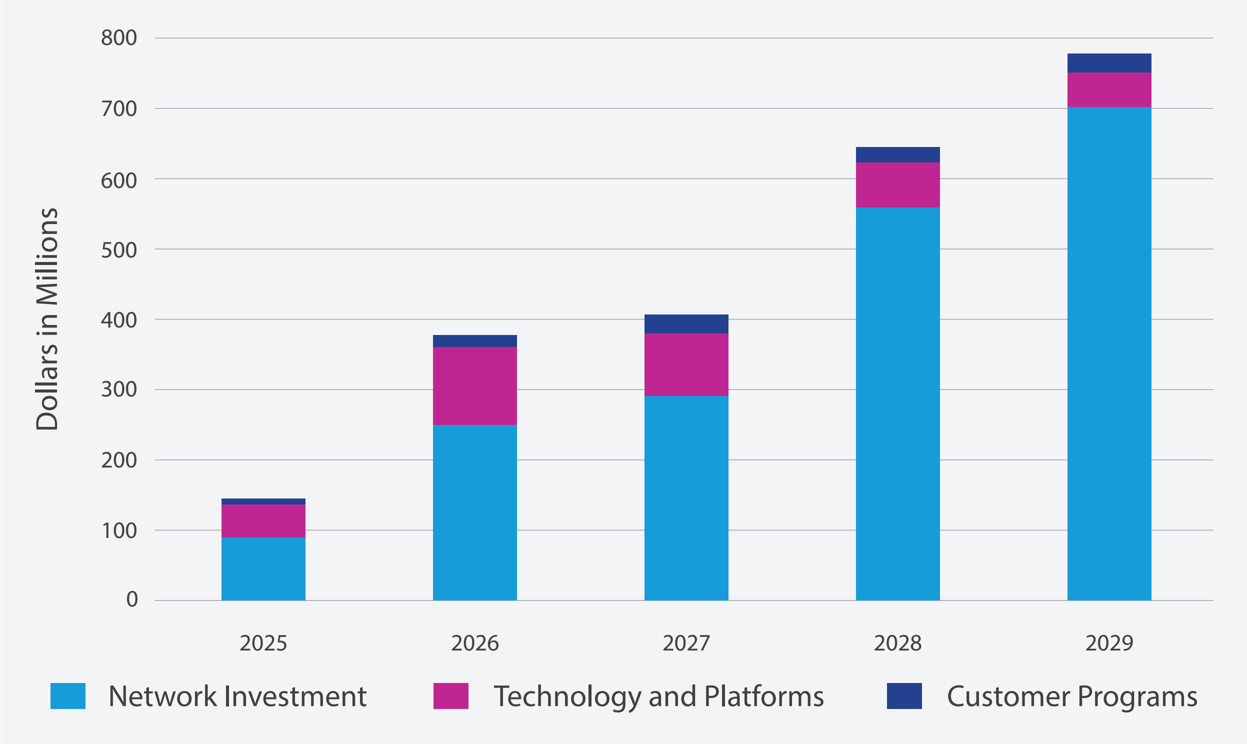
Ready | **Reliable** | **Resilient** | **Flexible** | **Efficient**

We are proposing to move away from a planning and investment approach that lags customer need and impedes technology deployment to one that anticipates and enables it. It takes a smarter, forward-looking view of system capacity and operational needs, on both a systemwide and a localized basis, to build sufficient capacity and resiliency and avoid the need for future investment. For example, to meet the Commonwealth's goals in the timeframes contemplated requires the accelerated adoption of electrified end use technologies powered by clean electricity. The grid therefore needs to be ready and the capacity available when customers choose to act and clean energy developers choose to invest – eliminating the lag they currently experience, which delays or deters this investment. This forward-looking, smarter approach to distribution system investment, on both a systemwide and localized basis, will create efficiencies in planning and capital deployment, provide opportunity for proactive community engagement and involvement, and ensure that no customer is left unserved as we move to a more electricity-reliant future.

We reviewed investments across three key areas:

- **Network Infrastructure**, such as new and upgraded power lines, transformers and substations to make them stronger, more resilient, and ready to connect and accommodate more clean and distributed energy and electric growth;
- **Technology and Platforms**, such as new planning tools, systems, and processes to drive smarter decision-making and customer action. This includes installing state-of- the-art data and monitoring systems to provide greater visibility into how the grid and interconnected devices are operating to ensure system safety and stability, and upgrading IT systems and communications networks to accommodate two-way information flows, and provide greater system flexibility and more timely information to support new customer tools and options; and
- **Customer Programs**, such as new programs and pilots to help customers better manage costs, drive smart energy use, and build community resilience and agency.

Proposed National Grid ESMP Investments 2025-2029



While the investments necessary to deliver this system will be significant, they are critical to meeting the Commonwealth's bold climate goals. Throughout the transition, the Company will continue to identify and pursue ways to efficiently deliver this clean, fair, and affordable future, including through the use of, for example, time-variable rates (TVR), energy efficiency, demand response and other forms of non-wires alternatives, so that we build only what is needed, where it's needed.

Achieving the just transition will require working together to make change

The Company recognizes that there are challenges associated with delivering the Commonwealth's ambitious climate and electrification goals, particularly within the time frames and pathway established by the CECP. These challenges include securing a trained and skilled workforce, maintaining an affordable and timely supply chain, and making changes to underlying regulatory policies, mechanisms and processes needed to execute this future. To manage the associated deliverability risks, the Future Grid proposed Plan prioritizes investment based on current system performance, distribution engineering planning needs, and execution strategy.

Meeting CECP goals requires policy action in four key areas to enable needed investments

- **Anticipatory Planning and Investment**
  Policies that enable and encourage utilities to build out the network so that the capacity is available, and the system is ready when customers need it. This shift will also allow utilities to plan for and train the necessary workforce and secure the necessary supply chain in what is an extremely competitive marketplace.

- **Permitting Reform**
  Policies that improve transparency and accessibility, provide greater agency to potential host communities, and create a more predictable and timely applicant process are needed. This includes establishing a one-stop shop approach to permitting, with clear and understandable standards and engagement practices that project applicants must meet to enable the more rapid delivery of critical infrastructure investments.

- **Environmental Justice**
  Policies must address both procedural and distributional equity, including expanded assistance programs to improve affordability of energy bills, and improved intergovernmental coordination to better serve impacted communities' total needs, while ensuring they have the resources to fully participate in the clean energy transition.

- **Demand Flexibility and DERs**
  Regulatory and tariff changes that enable time-varying rates and recognize the shift toward greater electrification are required to support more impactful offerings to offset peak demand growth with increasingly flexible loads and expanded deployment of distributed resources.

Given the scope and scale of the investment, continued stakeholder participation and input are vital to ensuring a collaborative approach. Our collective efforts must address the needs of all customers and end the cycle of overburdening EJCs and instead use this moment as an opportunity to take restorative action. The Company recognizes that we cannot succeed unless every community across the Commonwealth is engaged and included in the process, is empowered by the clean energy transition, and fully understands the investments and actions necessary to make it a reality. This public engagement effort is already well underway and will continue.

The Company also sees significant opportunities to create real customer value and economic, societal and community benefits, particularly for EJCs, through job growth, increased tax revenue for local communities, and economic expansion by building a clean energy ecosystem that drives competitiveness and growth and reduces climate pollution. Taken together with the Company's earlier investments in grid modernization, energy efficiency and transportation electrification, we believe that total benefits will well exceed costs in meeting the Commonwealth's energy and climate goals.

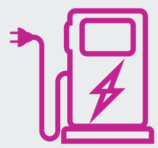
The Company's Future Grid Plan will deliver a stream of customer and community benefits

By 2030, jobs and other economic benefits, including:

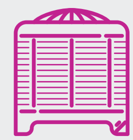
11K
Full- and part-time jobs

1.4B
Incremental economic output

By 2035, 4 GW of new system capacity, enabling:



1.1M
EVs



750K
Heat pumps

We recognize that we are foundational to achieving this new energy future, and that we cannot do it alone. We are committed to working collaboratively with policymakers, regulators, customers, communities, technology providers, and others to deliver a just energy transition for Massachusetts.

Together, we can make it happen.

1.1 Vision: Enabling a just transition to a reliable and resilient clean energy future

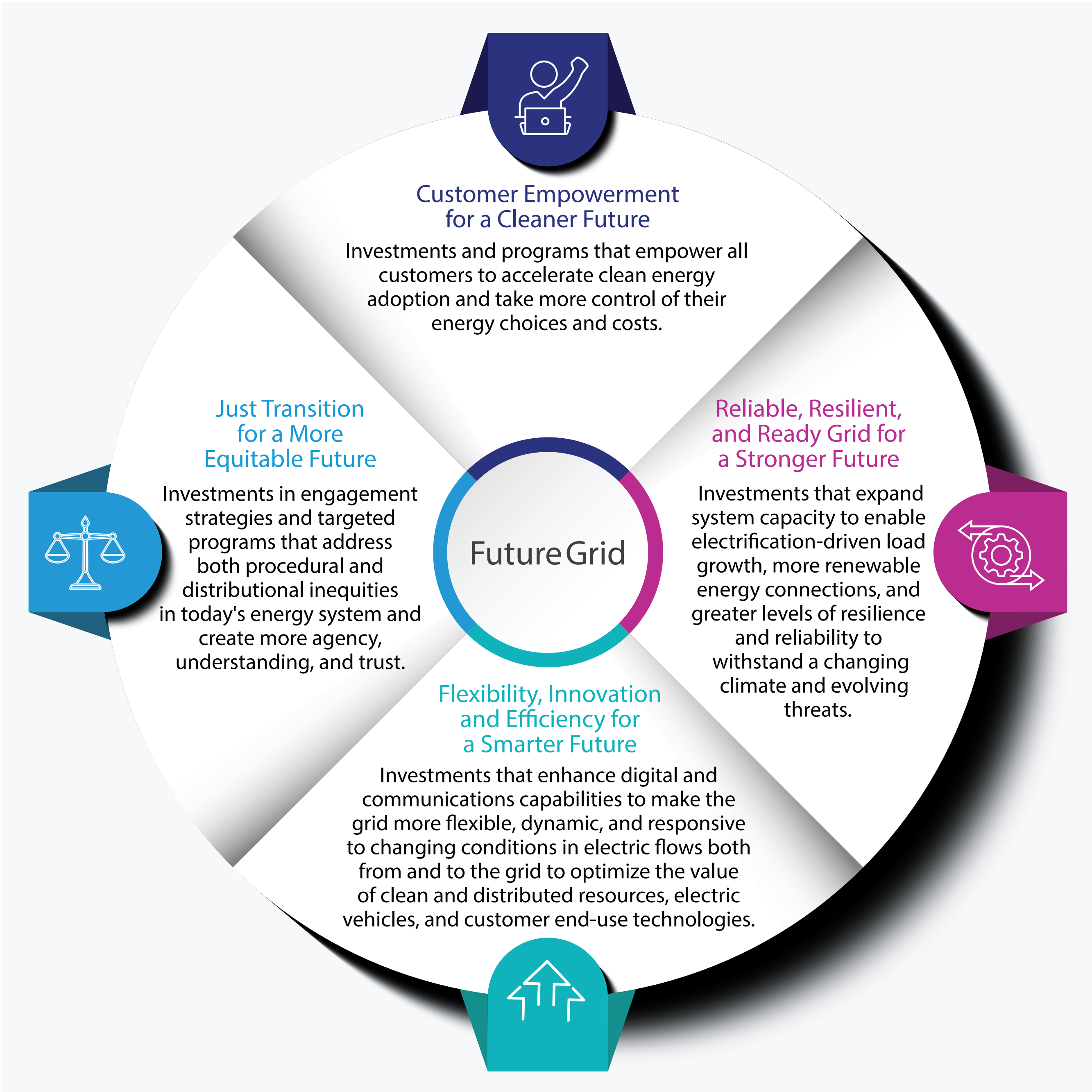
National Grid's vision is to be at the heart of a clean, fair, and affordable energy future for all our customers and communities.

At its core, the clean energy transition in Massachusetts is about re-imagining the future of the electric system, its relationship to customers and communities, its capabilities and opportunities, and the corresponding regulatory paradigms necessary to ensure we are proactively building the smarter, stronger, cleaner network needed to achieve desired outcomes, which include:

- Empowering customers to make the smart clean energy choices that work for them;
- Creating a ready, reliable and more resilient grid capable of withstanding more extreme weather;
- Leveraging innovation, driving efficiency, and enabling greater system flexibility; and
- Enabling a more just and equitable energy future to ensure benefits for all.

National Grid's approach to the clean energy transition starts with the customer—understanding their evolving energy needs, giving them more information and more choices, and supporting their side of the clean energy effort through programs, rates and other offerings. It then establishes the investment pathway necessary to meet these needs, using specific criteria to assess and develop the required investments in network infrastructure, technology platforms, and customer programs. The resulting investments will make the grid smarter, stronger, and cleaner, and will empower all customers to adopt clean energy technologies at the pace and scale needed to meet CECP goals. The graphic below summarizes our Future Grid vision.

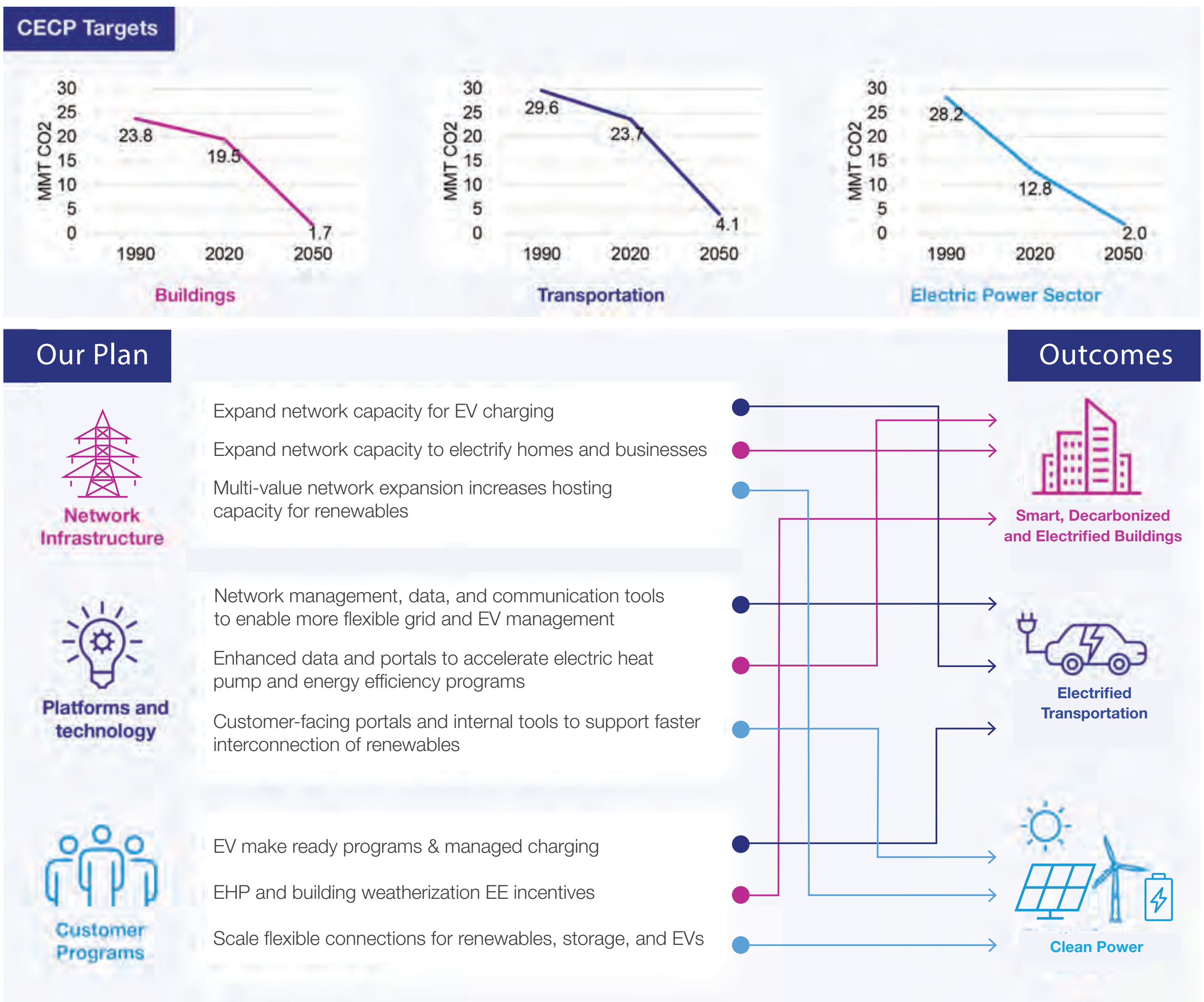
National Grid's Customer-Driven Future Grid Plan



1.2 Plan overview and alignment with the Clean Energy and Climate Plan

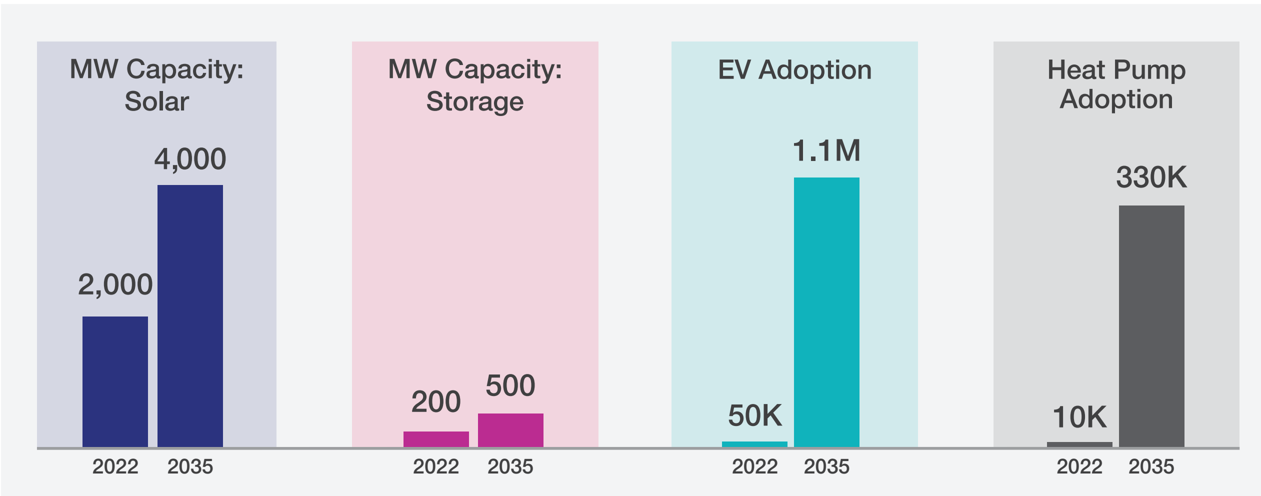
The 2050 CECP is the Commonwealth's plan to achieve economy-wide net zero greenhouse gas emissions by 2050. Future Grid is National Grid's plan to deliver an electric network that meets the goals of and is consistent with the CECP. The graphic below illustrates at a high level the CECP's sectoral emissions reduction goals, and how our proposed Plan's elements map to those goals.

How The Company's Future Grid Plan Elements Map to CECP Goals



Meeting these ambitious targets requires building an electric system that can support increasing amounts of intermittent renewable generation capacity and significantly increased electricity consumption in the transportation and buildings sectors resulting from policies that drive electrification. The graphic below provides selected growth projections by technology through 2035 that the grid must be able to accommodate on the path to 2050.

*Solar, storage, EVs, and heat pump adoption is expected to soar by 2035 and the grid must be ready**



*These are approximate values

How National Grid Will Meet the CECP Targets

National Grid will help Massachusetts deliver on its CECP targets for the transportation, buildings, and electric power sectors by investing in three key areas:

- **Network Infrastructure**, such as new and upgraded power lines, transformers and substations to make them stronger, more resilient, and ready to connect and accommodate more clean and distributed energy and electric growth;
- **Technology and Platforms**, such as new planning tools, systems, and processes to drive smarter decision-making and customer action. This includes installing state-of-the-art data and monitoring systems to provide greater visibility into how the grid and interconnected devices are operating to ensure system safety and stability, and upgrading IT systems and communications networks to accommodate two-way information flows, and provide greater system flexibility and more timely information to support new customer tools and options; and
- **Customer Programs**, such as new programs and pilots to help customers better manage costs, drive smart energy use, and build community resilience and agency.

These investments will support expanded energy efficiency and demand response programs, smart electrification and the connection of renewable energy and energy storage at all levels.

Accordingly, the Company's Future Grid Plan outlines the steps we need to take over the next five,10 and 25 years to achieve our collective goals. Because the Company took a long-term view of the investments required, it was able to anticipate the system needs for electrification forecast to occur beyond a typical 10–15-year study horizon. The investments included in this Plan are prioritized based on forecasted demand, known and anticipated system capacity and operational needs, and customer expectations and requirements. Absent this long-term vision, the Company in many instances would have needed to make successive investments in an asset or area, to react to electrification load growth and clean energy deployment, as it materialized. This approach would result in less cohesive solutions, and delays in meeting customer and community needs. Instead, through this Plan, the Company is proposing a smarter, more efficient approach with more anticipatory investments scaled to the needs of an electrified and decarbonized Commonwealth.

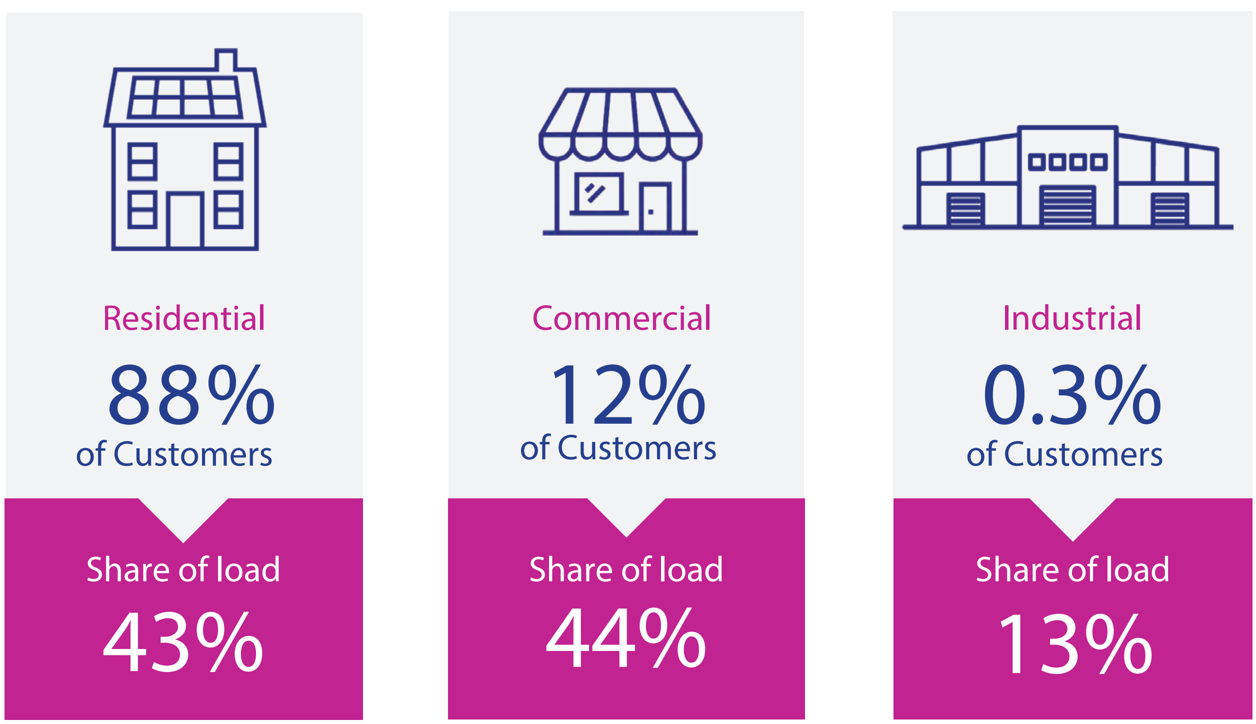
1.3 Service area overview (customers, load, transmission, distribution, generation)

Our customers and communities are at the foundation of what we do and why we do it, and they are critical to the success of the Commonwealth's decarbonization plans and achieving the CECP goals.

Customer Characteristics

Today, National Grid provides safe and reliable electric service to more than 1.3 million customers in 168 towns and cities, across a service area that spans nearly 3,870 square miles — from the Berkshires to Brockton and Cape Ann to Cohasset. We are the electric provider in many of the Commonwealth's Gateway Cities and we serve many environmental justice communities, representing customers in towns such as Adams, Worcester, Somerset, Lowell, Lawrence, Lynn, and others. We serve rural, suburban, and urban areas — including coastal and mountainous communities. Our customers live in single-family homes, multi-family homes, and apartment buildings. They run farms, small retail businesses, restaurants, grocery stores, food processing facilities, and more. They include municipalities and schools, ports and transportation hubs, academic institutions, manufacturing facilities, hospitals, healthcare, and life sciences. The graphic below summarizes our customers by major type and percentage of total load served.

National Grid Customers



While 88% of our customer base is comprised of residential customers, nearly 60% of the electric demand is driven by commercial and industrial (C&I) customers. Each customer segment has unique needs; and they are evolving. While residential customers' demand is lower than C&I, their needs are growing and the complexity and breadth of services and offerings they are asking for is following suit. For example, as more customers adopt behind-the-meter solar and storage, even though their overall electricity supply needs may decline, their use of and interaction with the grid and related services will increase. Similarly, as more C&I customers electrify fleets, their system use patterns and demand profile are changing, as well.

System Characteristics

To serve our diverse customer base, National Grid operates and maintains an electric system that consists of more than 2,500 miles of electric transmission lines. These transmission lines carry electricity long distances at high voltage levels to 149 transmission substations that serve a critical function of stepping down this power to a lower voltage and make it safe to carry it across 18,500 miles of smaller electric distribution lines, which are supported by hundreds of thousands of poles and 178 strategically located distribution substations in our six sub-regions. As the power flow of the network increases, the capacity of the substations must also increase to accommodate this growth. Substations play a pivotal role in stabilizing the entire electric network and maintaining safe and reliable service. Lower voltage electricity is distributed from the substation across a series of lower voltage circuits or wires, which can run overhead or underground. This power is then stepped down again at smaller transformers close to homes and businesses so that it can be safely delivered to customers. This extensive network will need to nearly double in size and capacity over the next twenty years, including adding a substantial number of new substations and expanding others, to meet our customers' future needs, and achieve the CECP goals.

In 2022, the Company's system carried electricity generated by solar, wind, hydro, nuclear, biomass and fossil fuels to meet 19,000 GWh of electric demand (1/3 of the state's total electric demand) and supported a maximum hourly demand of 4.7 GW. Our electric network also enabled the interconnection of 150 MW of solar and 50 MW of storage and supported a broader total of approximately 2 GW of DERs, including behind the meter resources like storage and solar on homes and businesses — more than any other EDC in the state and second most per square mile in the country.

Click here for an explanation of how the grid works.

For those customers that do not receive generation service from a third-party supplier or municipal aggregator, we purchase it on their behalf via the competitive wholesale power market and pass it along without profit or markup. The mix of generation we procure from these suppliers to deliver to customers will change as more and more of the power we purchase comes from renewable sources, such as offshore wind, hydro, and solar, enabling the Commonwealth to meet its goal of 97% of all electricity delivered coming from clean energy sources.

National Grid Summary Statistics

1.3M
Electric customer accounts

18K
Miles of electric distribution lines

178
Distribution substations

720K
Poles

Our interconnected network is kept in balance by our operations control centers which monitor and manage the network 24/7/365. The control center is the “orchestrator” of the network with real-time visibility into network conditions and is responsible for dispatching assets and field operations crews as needed in response to grid conditions. The role of our control center, and the teams that operate it, is changing with the accelerated adoption of DER and electrification across the network.

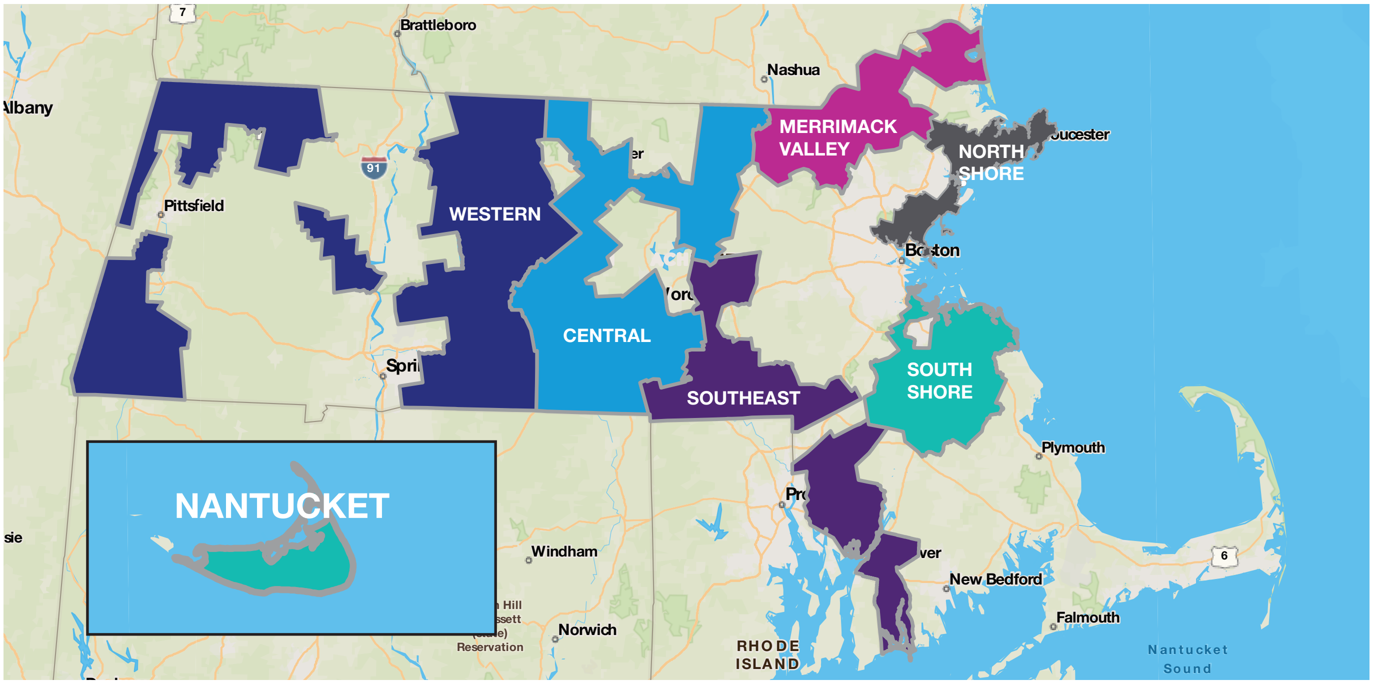
We are equipping our control centers and team members, accordingly with new tools, processes, and resources to operate a more dynamic and reliable network that leverages DERs as providers of grid services both at the distribution level and to the Independent System Operator of New England (ISO-NE) wholesale markets via Federal Energy Regulatory Commission (FERC) Order 2222, which will create additional value streams for resources like distributed solar, behind-the-meter storage, managed charging, and demand response.

Our community characteristics drive today’s system and tomorrow’s investments

The diverse communities we serve have unique physical, economic, and historical characteristics that informed the Company’s previous planning criteria and impact our operation in those areas today. For example, some communities previously supported the Commonwealth’s textile and manufacturing economy, while others had limited economic activity. Some rural areas are now becoming suburban, and urban areas that once thrived may have experienced limited growth for a long time. The results of these varied and uneven economic development and settlement patterns across our service area means that existing infrastructure and system capacity are varied and uneven, as well.

This foundation shapes and informs the investments needed to enable the clean energy transition and build resilience in each community. As we developed our Future Grid Plan, we took both a granular and high-level view of our system breaking it down into different distribution regions. These groupings are based on both geographic proximity and electrical system characteristics which facilitate effective system planning and engineering analysis. The map on the following page provides an overview of these six regions.

National Grid's Six Major Service Sub-regions

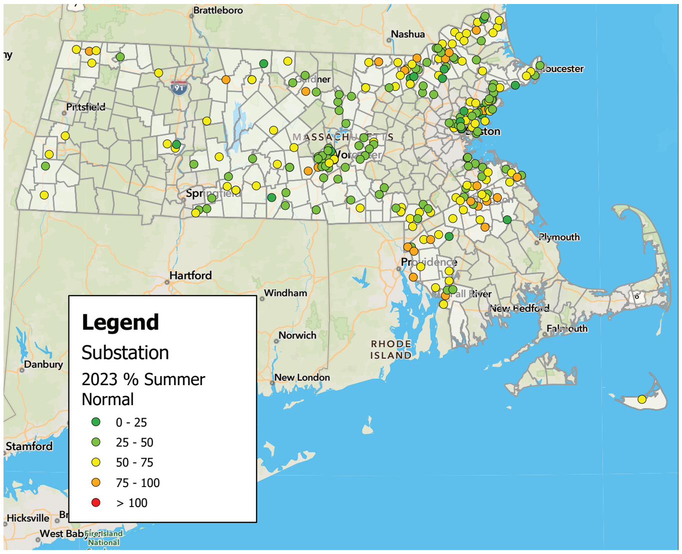


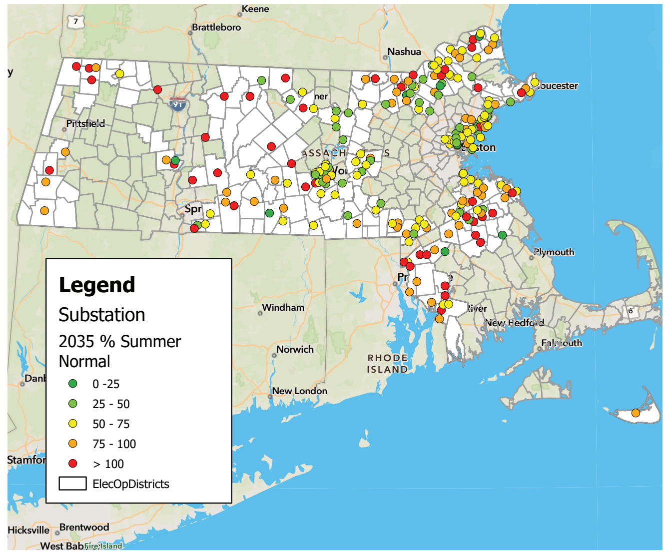
The Company analyzed the current demand, future needs, and existing system capacity in each of these regions. The maps below show that without system upgrades, by 2035 every region in our system will see forecasted demand exceed current capacity. We therefore need to invest in expanding and upgrading our electric delivery infrastructure in every region over the next 5, 10, and 25 years.

The scale, scope, timing and exact locations of these investments will be driven by a combination of factors, including 1) the physical and operational needs and the condition of the infrastructure used to serve these regions, 2) the available capacity on the local electric network to meet future electric needs and enable local, distributed energy resources like solar and storage, and 3) the current performance of the local energy network as it relates to reliability and resilience.

The map below illustrates the contrast between today's current loads vs. system capacity across our service area and sub-regions, and the projected gap between forecasted loads and current capacity in 2035. The 2035 projections show no system expansion investments; this provides a baseline for examining alternatives as we worked through the planning process applying our ESMP driven outcomes of ready, reliable, resilient, flexible, and efficient. Section 4 provides more detailed information.

Substation load as a percentage of capacity across the Company's system, 2023 vs. 2035 forecast, assuming no capacity expansion





Without system upgrades, by 2035 every sub-region in our system will see forecasted demand exceed current capacity.

1.4 How our customers will experience the clean energy transition

The future electric system will power not only the appliances, electronics, lighting, and cooling systems it serves today, but also the cooking of food, the heating of buildings, and the transporting of goods and people. Today, our customers rely on and use electric, gas, and delivered fuel networks to meet their home and building energy needs, and a vast network of fueling stations for their cars, buses, and trucks. In the future, customers will become much more reliant on the electric network to power all aspects of their lives and work. They will experience a future electric network that is more decarbonized, more distributed, more digitized, more decentralized, and even more necessary to them.

National Grid customers are increasingly aware of this future and engaged in their energy experience and the role energy plays in their day-to-day lives. As a result, they have high expectations for levels of service and options. They want immediate solutions when problems arise, when outages occur and when opportunities emerge. Rising prices, supply security concerns and climate change are front of mind. There are more active energy consumers seeking more interaction, driving a greater need for change in the customer experience. Each customer has their own unique needs, depending on a variety of factors, including customer type, electric use patterns, geography, income, and access to technology and capital.

We also know that affordability and equity mean different things to different customers. For some business customers, for example, electric costs may be a significant share of their overall operating costs, impacting profitability. For some residential customers, paying their monthly electric bill may require hard choices, such as choosing between heating or eating, because their energy burden is so significant. We are aware of these key differences and are re-envisioning how we approach, interact with, and serve each set of customers. This deeper understanding of our customers' diverse needs helps us define the investments needed to: improve operational efficiency; optimize our plans and programs to build only what is needed to meet reliability, resilience, and growth goals; and enable rate designs, energy efficiency, access to clean transportation, and customer and community- facing programs for bill management and other support.

Our customers' and communities' actions will determine the pace and scale of decarbonization in the Commonwealth. National Grid maintains a Customer Council comprised of all customer classes, service area communities, and impacted populations, including EJCs. In anticipation of our ESMP filing, we reached out and asked customers through the Customer Council about their expectations for the future energy system, what they want from the energy transition, and how they want to experience it. This customer feedback is summarized the box to the right and informed our Future Grid proposal.

Key takeaways from our Customer Council input:

Build a Grid that Serves Everyone

Strengthen our system

Create clean energy solutions, fewer outages, and thousands of jobs.

Keep Costs Down

Make smart investments that improve operational efficiency and enable customers to optimize and create value from energy systems.

Put Customers in Control

Deliver products and services that put customers in control of their energy future to meet their priorities, not ours.

Create a Seamless Experience

Continuously modernize our system so all customers can-self serve and more seamlessly access and sign up for products, services, and programs, with particular focus on our low- and moderate-income customers.

For McSwiggan's Pub in Weymouth, building renovations and staffing changes in their 2,400 square foot pub meant that costs were becoming an issue. The owners leveraged free energy assessments and the Company's small business rebate program to save them 73% of the total cost of removing its old HVAC system and upgrading to three new electric heat pumps. They were able to install equipment and connect to our system immediately, meeting their needs in their time frame.

1.5 Demand assessment and investment drivers

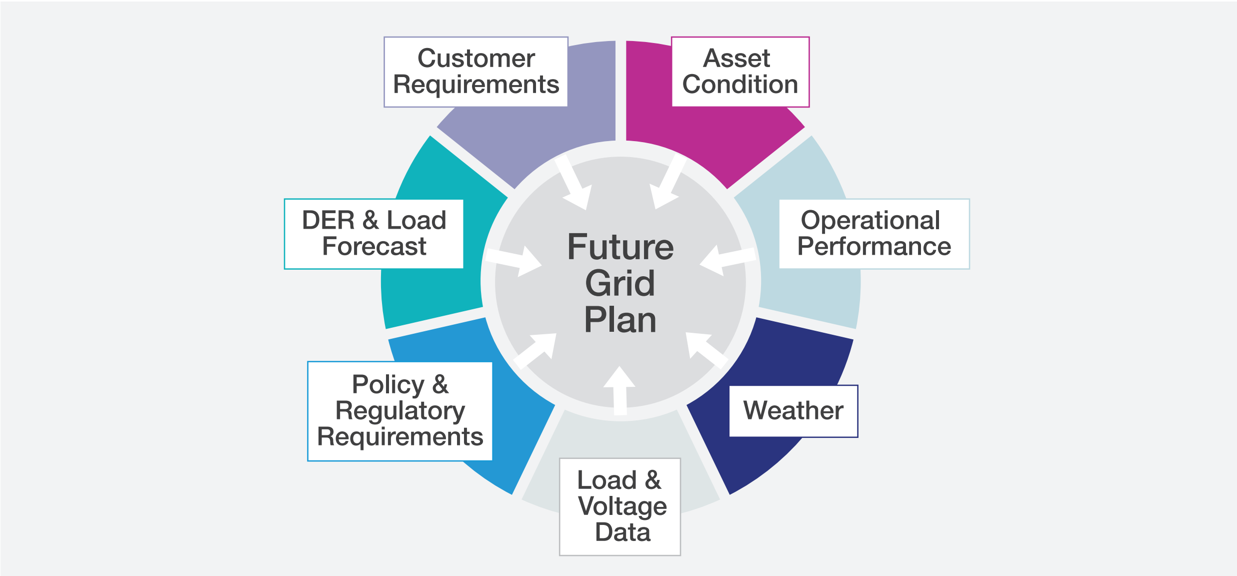
National Grid's system demand forecast is fundamental to meeting the Commonwealth's climate goals. The substantial beneficial electrification of heating and transportation needed to achieve the CECP goals impact the electric demand forecast dramatically, including peak demand and when it occurs, driving the need for infrastructure investment.

National Grid, like Eversource, uses an econometric forecast model to first project a base load estimate, and then incorporates adjustments for policy changes, technology innovation and adoption, customer behavior, and historical load and weather data with other factors to develop a predictive load forecast model. National Grid uses this model and data to run 2000 different scenarios of future electric load growth, including system-level and substation-level peak demand. Both Eversource and National Grid produce system- and substation-level peak 90/10 forecasts, taking the 90th percentile forecast load as the primary planning case. The graphic on the following page illustrates the inputs to our system analysis and modeling process.

How is electric demand expected to change in the future?

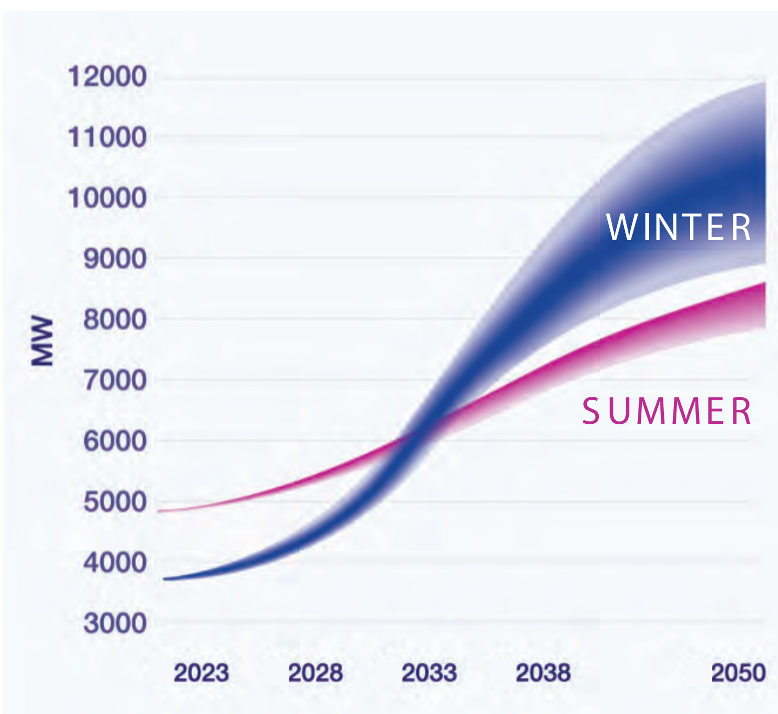
We are at an inflection point on our path to net zero emissions in terms of how customers use electricity. National Grid's electric demand is forecasted to grow at a rate that exceeds historical averages of the past 15 years and outpaces offsetting actions such as energy efficiency, demand response, and solar PV, as electrification in the transportation and buildings sectors creates significant new end-use demand for devices and at times that are different from historical patterns. For example, aggregate demand has remained relatively flat over the last 15 years despite increases in base load.

Principal inputs to the Company's system analysis and modeling process.



Over the next 10 years, however, customer usage is projected to increase, on net, at an average annual rate of 1.3% per year through 2029 and then increase to an average annual growth rate of 2.1% through 2034. In the post 2034 period, our total sales assessments anticipate electric demand growing at an annual average rate of 3%. These results of future electric demand are consistent with demand projections of Eversource, ISO-NE and the Commonwealth.

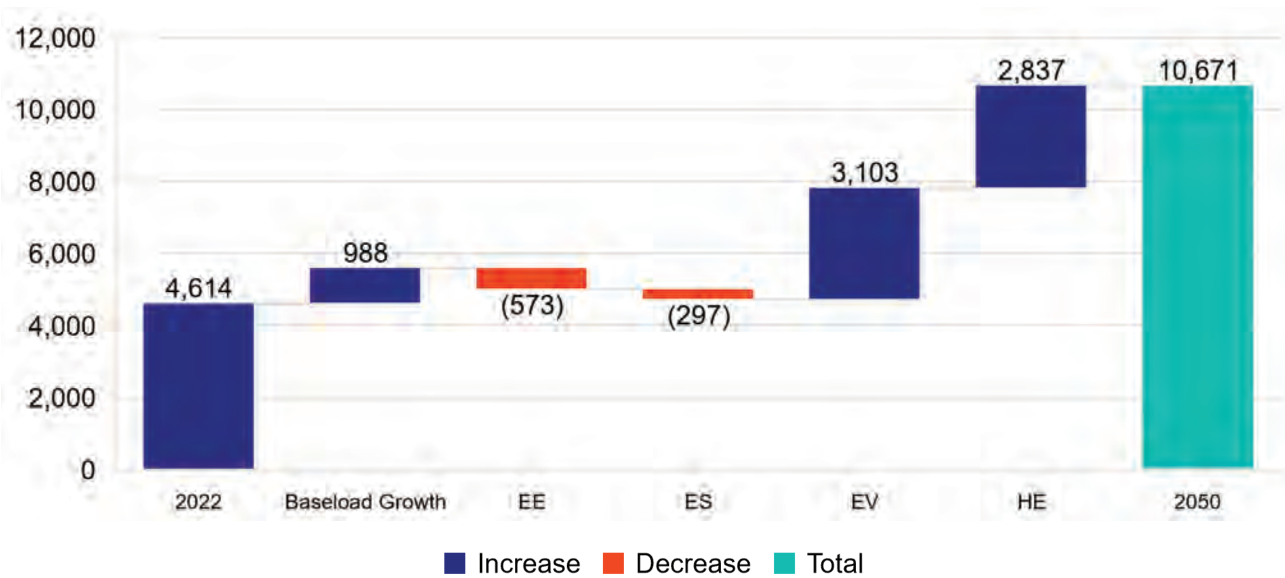
The Company's peak demand is forecast to more than double by 2050, and shift to winter around 2036



How is peak demand expected to change in the future?

Annual peak load, which is the maximum demand on the system in a given year, is expected to grow across our network 7% by 2029 and 21% by 2034 relative to 2022 levels, and more than double by 2050, driven by the electrification of transportation, heating, and industrial processes, as well as increasing air conditioning loads. And, while both summer and winter peak load are expected to grow, the graphic above shows that by 2036 winter peak load will exceed summer peak load, which has implications for system operations and the time of day when peaks occur. The graphic below provides a breakdown of the components of forecast load growth, including the potential impacts of efficiency, DERs, and other factors. See Section 8 for more detailed discussion of the demand assessment.

Annual peak load growth through 2050 by components



Our network investments and operational planning both need to change to accommodate these shifts. Enabling and accommodating the growth in electricity consumption from electric transport and heating will need the timely delivery of expanded electric system capacity on both the distribution and transmission networks. Without the necessary investment, accelerated rates of electric end-use technology adoption will outpace the grid's ability to keep up with demand in a manner that preserves reliability.

1.6 Equity focused stakeholder engagement and feedback

Seeking feedback, proactively engaging, and building understanding and trust with stakeholders is critical to achieving the Commonwealth's climate and clean energy goals. These include customers, communities, policymakers, public officials, non-governmental organizations, and technology providers, among others, who are both impacted by and important contributors to a fair, affordable, and clean energy transition Stakeholder engagement is also paramount to National Grid's ability to successfully develop and execute its Future Grid Plan, given the scope and scale of infrastructure investment needs, which includes the proposed upgrade and expansion of 17 existing substations, and building of 28 new substations more than 30 towns over the next 10 years.

To ensure we are gaining the necessary perspectives to inform our plans and siting decisions, we are taking steps to identify, map and innovate the best ways to engage and communicate with stakeholders on an individual and collective basis and provide more agency in the process. This includes leveraging available resources and forums, starting with the Grid Modernization Advisory Council (GMAC), members of the public, and experts who have participated in the process thus far.

Our approach to stakeholder engagement is rooted in the following:

Building a shared understanding amongst stakeholders regarding the electric grid, the goals of electric sector modernization plans, and how these investments will help the Commonwealth meet its climate and clean energy goals.

Developing collaboration by engaging stakeholders and establishing conversations to discuss the insights and initiatives required to deliver a smarter, stronger, and cleaner energy future and just transition, in ways that are relevant to them and meet community needs.

Tailoring outreach and stakeholder engagement plans to support local ESMP projects, elicit and incorporate customer feedback, and identify community concerns and needs. This will include a community-centric, culturally competent, and respectful approach to educate community members about the upgrades being made to the grid and the outcomes and tangible benefits they will deliver, and impacts.

We recognize that as we go about our outreach, solicit feedback, and seek to build trust, we must pursue engagement in a way that keeps communications simple, relevant, and timely, and that is also inclusive, accessible, open, and collaborative. To do this, we are holding direct dialogues and meetings in both facilitated forum and one-on-one settings, leveraging multiple and diverse communication channels through earned and paid media platforms, developing facts sheets and videos translated in multiple languages, and building digital tools such as websites and social content to provide all customers access to information about the ESMP process, National Grid's plans, and ways to provide input.

We are also conducting direct outreach with a focus on customers and communities that traditionally are not fully or formally represented in proceedings at the DPU or in processes like these, including environmental justice and LMI communities and constituencies, municipalities, small businesses, and labor.

In addition, we are leveraging existing data and customer research to better understand the outcomes our customers want and concerns they have as we make the energy transition, including through our Customer Council.

To date, we have met with more than 20 municipalities, 12 business and economic development organizations, including individual members, energy assistance providers, academic institutions, organizations representing generators, renewables, DER providers, EV providers and other technology providers, state officials, housing developers, and members at the EJ Table, which is a statewide coalition formed to inform and support environmental justice legislation and policy in the Commonwealth. (See list included in the Appendices.)

Procedural equity

To ensure that stakeholders and communities impacted by energy projects and programs have the necessary information and opportunity to participate in and inform project development and implementation.

Distributional equity

To ensure that the clean energy transition is implemented in a way that drives the more equitable realization of the benefits and burdens associated with the clean energy transition

To advance and operationalize these tenets as we continue to evolve and implement this Future Grid Plan, National Grid has developed a draft Equity and Environmental Justice Policy and Stakeholder Engagement Framework, which is included in the appendices. We are seeking feedback to this framework from the GMAC and Equity Working Group, among others, and will submit a final framework with our January 2024 filing at the DPU.

Feedback to date has focused on the following principal issues:

- **The importance of a deliberate transition, with the need to start engagement and planning with impacted communities and customers early in the process**. This early engagement is needed to ensure that we are capturing and addressing concerns and providing agency in siting decisions, coordinating work with municipalities, and identifying avenues for partnership and shared benefits, particularly for those communities that will either continue to host significant energy infrastructure or will need new investment. This includes working with trusted community partners throughout the process. Additionally, several municipalities viewed the transition as an opportunity to meet multiple goals for clean energy and economic development, by leveraging the process to create clean, electric-ready new business zones in their communities.

- **The need to maintain an affordable and reliable energy system**, with the recognition that affordability and reliability means different things – and have different implications – depending on customer segment and economic circumstance. The need to focus on the costs of the energy transition to EJCs, more holistically address overall energy burden and raise enrollment in existing affordability and assistance programs was raised several times. Many stakeholders focused on the need to ensure the system was resilient and able to respond quickly to any event, particularly as the economy becomes more electrified. For businesses for which electricity is a critical input, such as life sciences and biotech, power quality was also top-of-mind.
- **The challenges customers and technology providers have today to interconnect to our system quickly and affordably**, and the need to make it easier to do business with us. This issue was particularly acute for housing, commercial real-estate developers, and DER providers. There is a recognition that National Grid is working to shorten and simplify processes and secure the necessary supply chain, but that more needs to be done, particularly as the pace of electrification and clean energy deployment accelerates.
- **The benefits of Mass Save and other programs that provide financial and technical support to pursue clean energy and energy efficient solutions**, and the need to expand those programs, such as Community First, and make them more tailored and targeted to individual customer segments and circumstances. Many municipalities are concerned about the costs of the energy transition and ability to participate fully, not only for their own facilities, but also for their constituents.

Going forward, we plan to conduct additional and extensive outreach in advance of our final submission of our Future Grid Plan to the Department of Public Utilities (DPU) in January, including conducting joint outreach sessions with Eversource and Unitil. National Grid and the other EDCs are committed to hosting two stakeholder workshops in the fall of 2023 as part of the ESMP filing process. The fall workshops will be conducted in consultation with the GMAC, be professionally facilitated, hosted virtually, and conducted at times recommended by the GMAC or Equity Working Group, with language translation services. The EDCs will also use these workshops as an opportunity to further educate stakeholders and gain feedback from the voices of the community. We will track and share all recommendations and develop a formalized feedback loop for increased transparency.

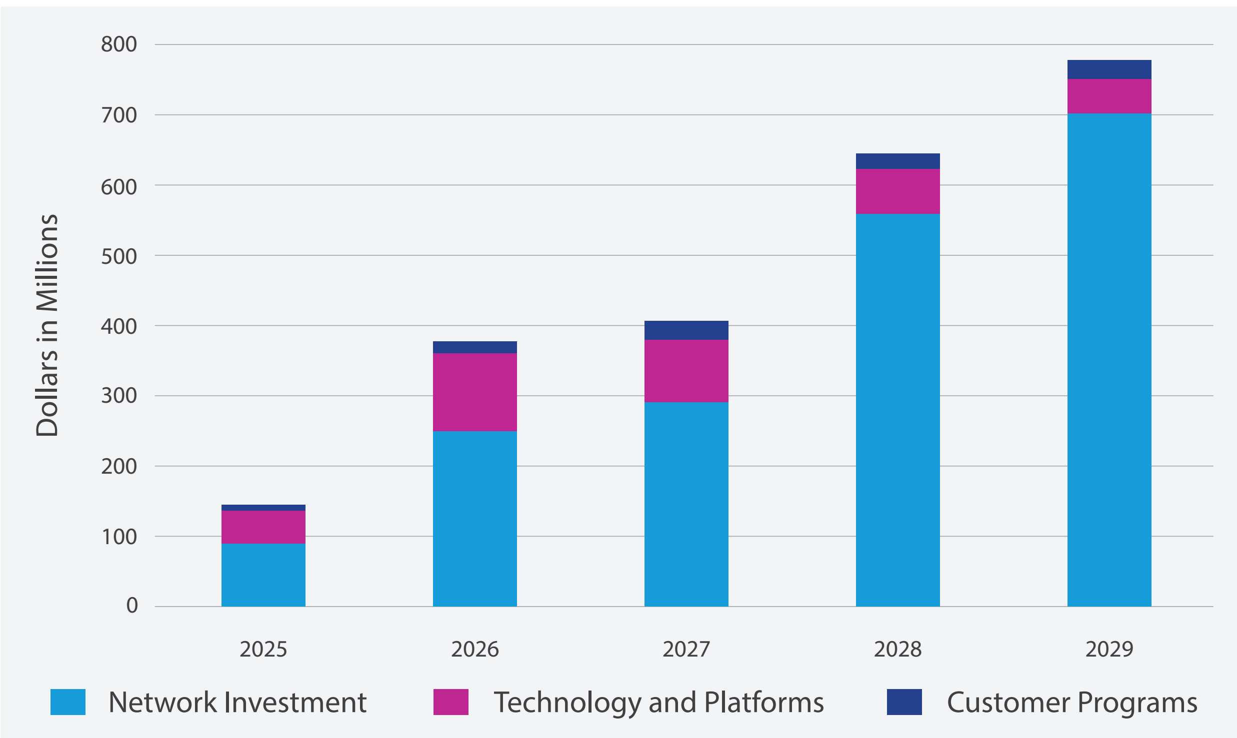
Proposed new Community Engagement Stakeholder Advisory Group

We are proposing jointly with the other EDCs the development of a new Community Engagement Stakeholder Advisory Group (CESAG) to address historical obstacles to stakeholder engagement and agency and ensure the widest possible level of community participation as we advance substantial investment plans that have a direct impact on and associated benefits to individual communities. Additional detail on the proposed CESAG is provided in Section 3.

1.7 5-year Electric Sector Modernization Plan investment summary and outcomes achieved

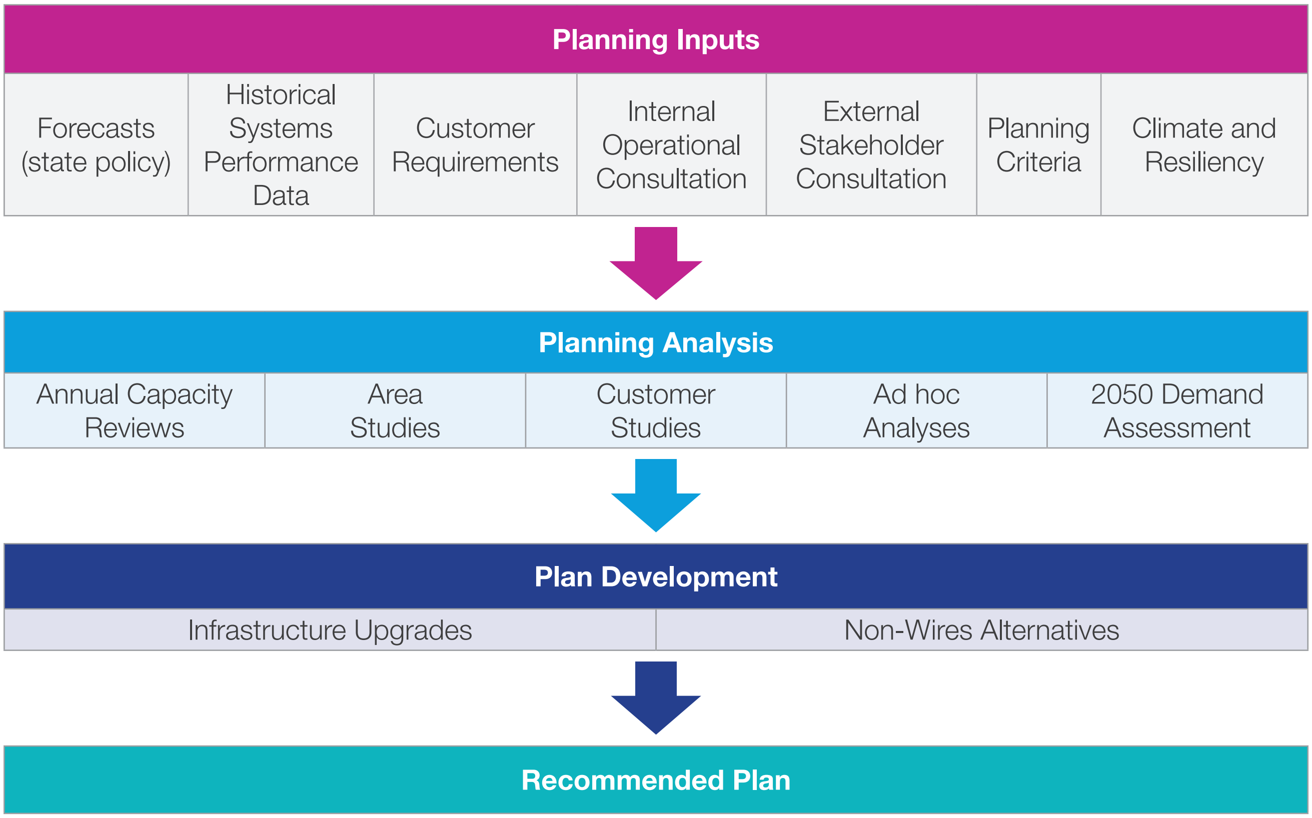
Over the next five years, National Grid proposes to invest more than $2 billion to meet the Commonwealth's electric-based approach to meeting its climate and clean energy goals and enable the just transition. As proposed in our Future Grid Plan these incremental investments focus on 1) network infrastructure, 2) technology and platforms and 3) customer programs. They have been carefully scoped to meet specific needs based on forecasted demand and identified system capacity and operational challenges. The graphic below summarizes our proposed investments by investment type.

Proposed National Grid ESMP Investments 2025-2029



These network investments include the upgrade and expansion of 10 existing substations, and building of 3 new substations over the next 5 years, and 18 existing and 28 new substations by 2034. They are driven primarily by adoption of electric transportation and building heating, which, as described in Section 5, are expected to increase the peak load across our network by 7% by 2029 and 21% by 2034 relative to 2022 levels. Absent making these system investments in advance of these new peak demand levels, the expected load growth will result in overloads of existing equipment, which would impact the safety and reliability of our network operation. In Sections 6 and 7, we provide details on the planning process and proposed investments across our network to proactively address these expected overloads and other needs; it explains the key factors driving these investment needs, including unacceptable asset condition and reliability performance concerns and the outcomes we established for the ESMP to assess each investment – reliable, ready, resilient, flexible, efficient. The graphic below provides a summarized view of our detailed planning process.

The Company's system planning process



These proposed investments will ensure that over the next five years we can deliver more than 1 GW of capacity to support our customers' adoption of electric transportation and building heating and enable more DER on the system. But to achieve these results the proposed network investments need to be made proactively, not reactively.

How energy efficiency, load flexibility, and other non-wires alternatives fit into the Future Grid Plan

Through the Commonwealth's investment in its nation-leading energy efficiency and demand response programs, the Company has avoided significant demand growth over the last decade, keeping annual load growth under 0.2% per year on average. By comparison, our forecasts show load growth starting at 1.3% per year, ramping to more 3% annual average load growth over the 2025-2050.

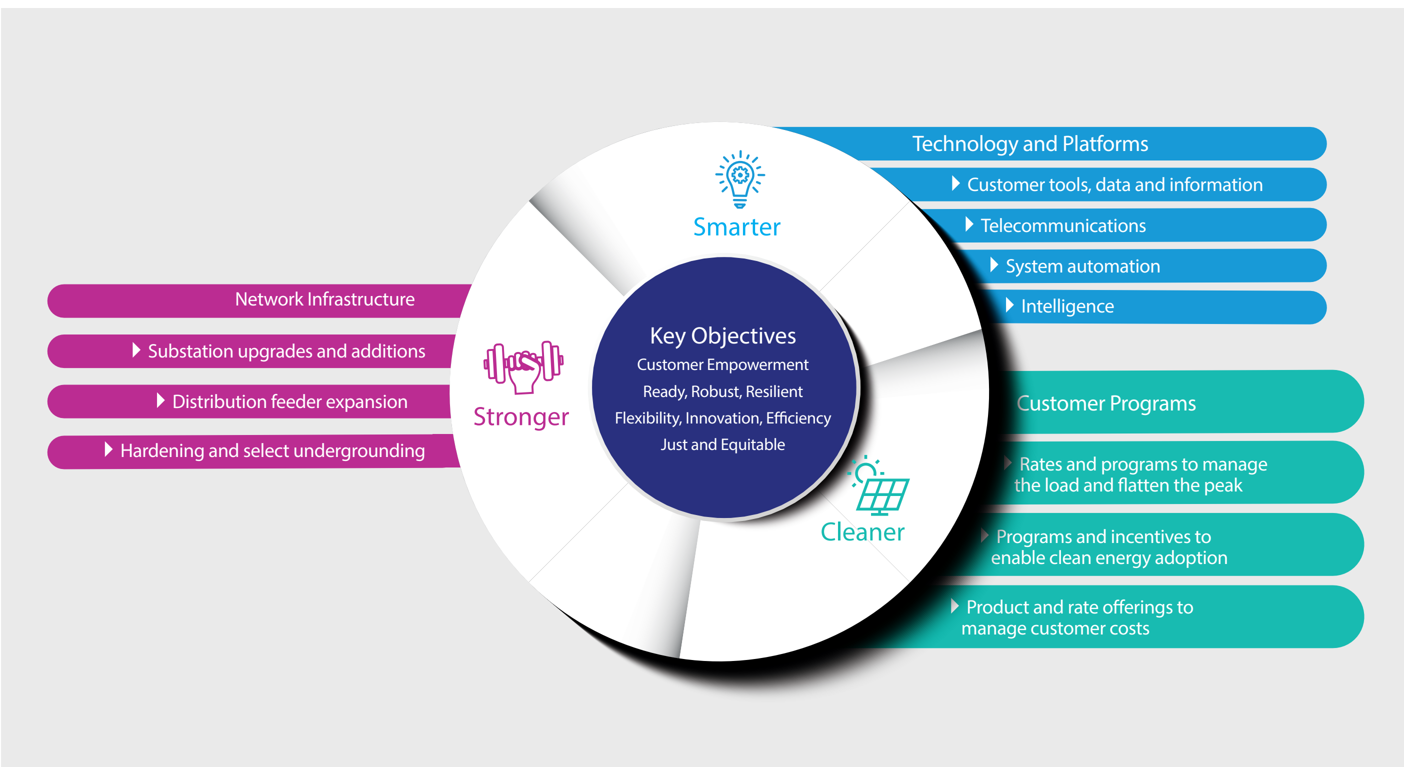
The Company will continue to advance significant energy efficiency savings through Mass Save, though more funding is expected to be targeted toward beneficial electrification. Concurrent with these investments, we will increase load flexibility from demand response and EV managed charging programs, though peak load impacts are forecast to be small in the next five years and will not have a material impact on overall system capacity and operational needs. In the next investment period – six-to-10-years—we anticipate more flexible load solutions to be available and more programmatic options to emerge, particularly as investments in the underlying communications and technology integration platforms materialize, allowing us to better manage and orchestrate these opportunities.

We also recognize that on a localized basis, flexible load solutions could provide opportunities to defer investments from the six-to-10-year time horizon to the following five-year period as well as meet more immediate needs, where we will not be able to build or expand traditional network infrastructure quickly enough to meet growing demand. To better understand the ability of these “bridge to wires” solutions to deliver required localized capacity and operational needs, National Grid is proposing both near term investments and pilots to advance these solutions through localized NWAs, including using distributed solar and batteries to create “Virtual Power Plants,” and applying newly deployed AMI infrastructure to advance TVRs and managed charging. A broader discussion on this topic is included in Section 6.

The Company’s investments will realize multiple outcomes for customers and the system

- Enabling an additional 4 gigawatts of capacity by 2035, enough to support an additional 1.1 million electric vehicles, 750,000 electric heat pumps;
- Upgrading hundreds of feeders to enable the connection of more clean distributed energy resources; and
- Improving local air quality as more cars, buses and trucks are electrified.

The Future Grid plan investments will make the Company’s grid smarter, cleaner, and stronger



As customers become more aware of and more educated on the emerging clean energy future, they are developing new expectations on accessing energy use data, monitoring their consumption, becoming more efficient, and participating more actively in energy markets. We anticipate customer participation in energy markets will continue to grow, particularly with the launch of FERC Order 2222.

Our Future Grid Plan recognizes these evolving expectations as opportunities. The Plan meets them through an integrated set of programs and investments that leverage communications and IT technology upgrades, like Advanced Distribution Management Systems (ADMS) and Distributed Energy Resource Management Systems (DERMS), which are currently being implemented. These IT platforms better enable and optimize smart devices, EVs, and demand response, which will be incentivized both in this Plan as well as through Mass Save energy efficiency and electrification programs.

Proposed additional clean energy offerings to support ESMP objectives

	Reliability	RE / DER	Storage	Climate Impacts	Electrification	Ratepayer Impact
Scale and evolve clean energy programs for Energy Efficiency, Heat Pumps, and Demand Response (through future separate filing)	✓		✓		✓	✓
Scale and evolve Clean Transportation Programs					✓	
Flexible Connections for EVs – Offer commercial and fleet EV charging customers to connect fleets in advance of system upgrades in constrained areas by allowing NG to actively manage charging					✓	
Targeted Energy Efficiency and Demand Response as Non-wire Alternatives – Offer additional EE and DR incentives to customers to reduce peak load based on targeted distribution network constraint	✓	✓	✓		✓	✓
Virtual Power Plant as Non-Wires Alternative – Aggregate BTM solar, connected batteries and thermostats to deliver grid services based on targeted distribution network constraint	✓	✓	✓		✓	✓
Leverage Flexibility Market Platform for Non-Wires Alternatives – Run auctions for flexibility service products based on targeted distribution network needs	✓	✓	✓		✓	✓
Resilient Neighborhoods Program – Develop and build solar + storage projects in EJCs to deliver resiliency benefits (through future separate filing)	✓	✓	✓	✓		
Time-Varying Rates – Offer customers AMI-enabled rates that support smart use of the grid and reduce the overall costs of the clean energy transition (through future separate filing)			✓		✓	✓

Acronyms - See Glossary in Appendix 14.0

1.8 Climate impacts and building resilience

Climate change is already affecting the Commonwealth's weather in dramatic ways. Historically, National Grid's system could expect four major storm events with significant outage impacts each year; now the expectation has risen to ten storms per year. These storms can also be more intense and localized, creating wind and flood damage. Higher summer temperatures and humidity levels are generating multiple effects, from increased customer cooling saturation rates, higher cooling usage, higher summer peaks, and de-rating transformer capacity. Winters, while milder overall, are also subject to 'polar vortex' conditions that bring intense cold and snow, with corresponding outage risks and peak demand impacts. While National Grid has maintained reliability at levels exceeding 99.9% of system-wide availability, we recognize that such climate impacts present risks to sustaining our high levels of system reliability.

At the same time, the Commonwealth's climate and clean energy goals add potential system reliability risks as we work to integrate grid-level renewable generation and storage, DERs, and new loads from beneficial electrification. Distribution system resilience and reliability must address these among other contributing factors, and National Grid has developed robust processes to respond to impacts on distribution system performance. Accordingly, preparing for and responding to the potential impacts of climate change is embedded in the way we plan, construct, and operate our system. As our understanding of the magnitude, scope, and breadth of climate-related challenges matures, the flexibility and robustness of the Company's processes will allow additional measures to be developed and implemented. Our approach to system reliability and resilience is summarized below.

The Company's distribution system reliability and resilience initiatives

Distribution Construction Standards	Regular reviews and updates of distribution construction standards to address environmental change and its impact on system reliability performance.
Vegetation Management	Developing long-term strategy, planning, budgeting, and delivery of the vegetation management work plan to address vegetation impacts on safe and reliable service.
Asset Management Practices and Distribution System Planning	Practices and studies to identify existing and projected future system performance concerns and the infrastructure development required to address them.
Infrastructure Development Programs	Programs designed to address the addition, replacement, and/or modification of specific assets.
Distribution Resiliency Hardening Programs	A Resiliency Strategy which establishes an approach to identify, prioritize, and mitigate Company circuits that have demonstrated historical resiliency challenges. The strategy focuses specifically on hardening the investments that are anticipated to increase the resiliency of the distribution system.
Asset Climate Vulnerability Assessments	Consider the impacts of climate change over the next several decades to determine future risk to our built and future electric infrastructure. Identifying climate hazards including flooding, heat waves and high temperature, extreme wind, ice accretion, and wildfires.

To identify climate hazard risk, the Company developed the Climate Change Risk Tool (CCRT). "Climate hazard risk" relates to the physical and operational impact of changing climate hazards to our electric assets due to increasing chronic hazards and intensifying extreme acute hazards because of climate change. Climate hazard risk consists of three components:

Risk = Hazard X Vulnerability X Exposure

The CCRT is the first of its kind in the energy sector and will help our business accurately map how our electric infrastructure may be impacted by climate hazards – such as floods or heatwaves – and to take early preventative and adaptive measures to significantly lower the risk of disruption to power networks, equipment, and communities, decades into the future.

Section 10 provides an overview of the approach the Company is taking to climate risk mitigation, shows how we applied the CCRT in this Plan, and includes specifics actions we intend to take over the next five years to make our system more resilient. For example, the Plan proposes a new demonstration program targeting distribution circuits which have experienced large numbers of tree-related outages over the last three years and increasing minimum clearances between vegetation and power lines. We have also identified 13 substations as being at a high risk of flooding, which could damage critical equipment such as transformers, circuit breakers, and relays, and we have included investments to mitigate these impacts.

1.9 Workforce and societal benefits of a just transition

The investments made in the distribution network and customer programs through the ESMP will enable a variety of environmental, climate, and health benefits. Benefits will be realized at local and state levels through emissions reductions, improvements in air quality, and greater resilience.

In addition to energy and local environmental benefits, our Future Grid proposal is projected to increase economic activity on the order of $1.4 billion and create an additional 11,000 jobs by 2030 throughout the Commonwealth, because of the labor resources required in construction labor, engineering, and planning and support functions to execute the Plan. These roles will include a mix of shorter duration work to support the build out of the network in the first five to 10 years of the Plan, and operational support function employment to support the network in operation. They will also include employees operating and managing grid performance and communications and IT platforms, as well as in the design and implementation of customer programs that support the electrification of heating and transportation, DER deployment, and other programs envisioned by the ESMP.

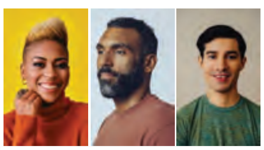
In addition to the direct expenditures associated with the proposed network investments, increased construction activities and infrastructure build-out will have positive tax and revenue impacts for some communities that host the planned infrastructure. For example, today, National Grid pays nearly $240 million in state and local property taxes.

National Grid recognizes these changes as an opportunity to provide opportunities to local communities – particularly those that have not historically benefited from — or have been burdened by — such investment. To enable this, National Grid has launched a multi-pronged workforce development pilot program, focused on EJCs to provide the foundational training and education to create a talent pipeline from these communities.

The Company's workforce development strategy is built around 4 strategic pillars:

- Work-ready adults ready to reenter the workforce;
- College/university graduates starting their career;
- Traditional and vocational technical high school student passionate about learning in-demand skills; and
- Middle schools that promote STEM awareness of the Commonwealth's climate and clean energy goals.

Workforce development pilot program academies

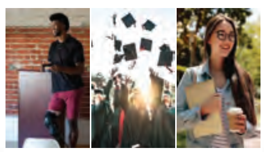


Energy Infrastructure Academy

- **For Work Ready Adults**
- **Up to 15 participants**
- **~200 hours of training**

Academy Focus:

- ✓ Immersive upskilling
- ✓ Training in high-demand, high-value energy and utilities skills
- ✓ Enabling participants to apply for full-time, competitive union roles



Clean Energy Careers Academy

- **For College and University**
- **Up to 30 students**
- **8-weeks**

Academy Focus:

- ✓ Engage students about the energy and utilities sectors
- ✓ Provide professional development
- ✓ Create connections that can lead to future internships, Co-ops, and full-time employment

Clean Energy Tech Academy

- **For High School and VocTech**
- **Up to 50 students**
- **3 to 5-day engagement**

Academy Focus:

- ✓ Explore energy and utility sector careers
- ✓ Discuss different career pathways at National Grid
- ✓ Provide professional development

Clean Energy STEM Academy

- **For Middle School**
- **Up to 30 students**
- **3 to 5-day engagement**

Academy Focus:

- ✓ Introduce students to National Grid and energy career options
- ✓ Interactive / hands on sessions about energy and utilities sectors
- ✓ Discuss energy concepts (e.g., electricity, gas, renewable energy, sustainability, etc.)

National Grid launched this pilot program in spring 2023, and and we have already hired 15 graduates from our Work Ready Adults program. In our Future Grid Plan, we are proposing to expand our Workforce Development Program to increase the number of individuals we put through this program.

The Company's Future Grid Plan will deliver a stream of customer and community benefits

By 2030, jobs and other economic benefits, including:

11K Full- and part-time jobs

1.4B Incremental economic output

By 2035, 4 GW of new system capacity, enabling:

1.1M EVs

750K Heat pumps

1.10 Conclusion and next steps

The Commonwealth's CECP is an equity-centered plan rooted in decarbonizing the electricity consumed by EDC customers and using this clean electricity to power all aspects of the economy, including homes, businesses, and transportation by 2050. Meeting the CECP goals requires all the Commonwealth's EDCs to develop comprehensive, thoughtful, and flexible plans that transform today's electric distribution grid, giving it new capabilities and expanding it at pace and scale to support this future, which will result in a doubling of electric demand over the next 25 years and the need connect and integrate at least 10 times the amount of renewable energy, 75 times the number of EVs, 150 times the number of heat pumps, and 2 times the amount of energy storage than today.

By developing and submitting this Future Grid Plan as our ESMP to the GMAC, the Company is taking a first step to defining the scope and scale of what we collectively must do over the next five, 10, and 25 years to combat climate change and enable a more electrified future. We are doing this by identifying the system investments and changes needed in the electric distribution system to meet growing demand, engaging broadly to stimulate ideas, and seeking input to ensure our investments are responsive to and supportive of the needs and expectations of our all customers and communities and make it easy to adopt the clean energy choices that work for them.

As a next step, the Company will work with Until and Eversource to conduct joint, professional facilitated technical sessions and other outreach to share our proposed plans, solicit feedback and educate customers throughout the state about the ESMP process and what it means for their energy future. We will take this feedback and incorporate it into our final submission to the DPU in January 2024.

Going forward, it will also be important to establish robust, consistent metrics to make our progress transparent and hold us accountable to ourselves, our customers, and to the Commonwealth for the proposed outcomes. Working with the Commonwealths' other EDCs, we have identified the following metrics to be further developed and ultimately tracked with specific indicators and reporting methods.

Metric Category	Metric Description
Implementation	Delivery of ESMP investments relative to established milestones
Resiliency	Customers benefitting from resiliency investment and improvements in relevant outage statistics
Electrification and DER Hosting Capacity	Amount of Electrification and DER capacity enabled on the distribution system
Use of DER as a Grid Asset	Amount of capacity enabling Grid Services and Flexible Load
Stakeholder Outreach	Specific engagements with stakeholders including those in EJ, disadvantaged or under-served communities

Together, we can make lasting changes that build a smarter, stronger, cleaner and more equitable energy future that empowers all who call Massachusetts home.

Section 2
Compliance with the EDC requirements outlined in the 2022 Climate Act

This section summarizes the statutory requirements and objectives for the ESMPs outlined in the 2022 Climate Act and explains how the Future Grid Plan addresses them.

2.0 Compliance with the EDC Requirements Outlined in the 2022 Climate Act

The Company's ESMP, this Future Grid Plan, 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. However, absent more accelerated investments in the distribution system and the transmission system, where applicable, it will be increasingly challenging to support these state climate and energy policy goals and increased customer demand for electricity. The Company has been an active partner in achieving the Commonwealth's goals, including past efforts focused on grid modernization and distributed energy resource (DER) penetration. Prior investments alone are not sufficient to achieve a comprehensive and holistic transition to a decarbonized and electrified 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.

Purpose

In accordance with G.L. c. 164, § 92B(a), the Company's ESMP has been developed to proactively upgrade the distribution system (and, where applicable, the associated transmission system) to: (i) improve grid reliability, communications and resiliency to all sub-regions (Sections 4.0, 6.0, 9.0, and 10.0 on reliability and resiliency, and Sections 6.3 and 9.8 on communications); (ii) enable increased, timely adoption of renewable energy and DERs (Sections 5.0, 6.0, 7.1, 8.0, and 9.0); (iii) promote energy storage and electrification technologies necessary to decarbonize the environment and economy (Sections 5.0, 6.0, 7.0, 8.0, and 9.0); (iv) prepare for future climate-driven impacts on the transmission and distribution systems (Section 10.0); (v) accommodate increased transportation electrification, increased building electrification and other potential future demands on distribution and, where applicable, the transmission system (Sections 5.0, 6.0, 8.0 and 9.0); and (vi) minimize or mitigate impacts on the ratepayers of the Commonwealth, thereby helping the Commonwealth realize its statewide GHG emissions limits and sub-limits under chapter 21N (Sections 7.1 and 9.0).

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 beneficial solutions for future electrification, renewable and DER integration, decarbonization-driven economic and environmental transitions, and customer empowerment.

Information Considered

The Company's ESMP 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 (Sections 4.0 and 10.0); (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 (Sections 6.11 and 9.0); (iii) patterns and forecasts of DER adoption in the Company's territory and upgrades that might facilitate or inhibit increased adoption of such technologies (Section 5.0 and 8.0); (iv) improvements to the distribution system that will enable customers to express preferences for access to renewable energy resources (Section 9.0); (v) improvements to the distribution system that will facilitate transportation or building electrification (Sections 5.0, 6.0, 8.0, and 9.0); (vi) improvements to the transmission or distribution system to facilitate achievement of the statewide GHG limits under chapter 21N (Sections 5.0, 6.0, 7.1, 8.0, and 9.0); (vii) opportunities to deploy energy storage technologies to improve renewable energy utilization and avoid curtailment (Sections 4.3.5, 4.4.5, 4.5.5, 4.6.5, 4.7.5, 4.8.5, 5.2.5, 9.1.4, and 9.6.2); (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 (Sections 7.1.1, 9.1 and 9.5); 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 (Sections 7.1.2 and 9.6). 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 DERs, avoided renewable energy curtailment, reduced GHG and air pollutants, avoided land use impacts and minimization or mitigation of impacts on the ratepayers of the commonwealth (Sections 6.3.1, 7.1.3, and 12.0).

Further, in this plan the Company complied with the requirement to prepare and use three planning horizons for electric demand, including a 5-year forecast (Section 5.0), a 10-year forecast (Section 5.0) and a demand assessment through 2050 to account for future trends, including, but not limited to, future trends in the adoption of renewable energy, DERs and energy storage and electrification technologies necessary to achieve the statewide GHG limits and sub-limits under chapter 21N (Section 8.0). G.L. c. 164, § 92B(c)(i) The Company also considered and includes a summary of all proposed and related investments (Section 7.1), alternatives to these investments and alternative approaches to financing these investments (Sections 7.1.1 and 7.1.2) 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 GMAC established in section 92C, responded to information and document requests from said council and conducted technical conferences and a minimum of two 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 3.0). G.L. c. 164, § 92B(c)(iii).

Proposed Investments

The Company's ESMP proposes discrete, specific, enumerated investments and alternatives to meet the statewide GHG limits and sub-limits under chapter21N through enabling a just transition to a reliable and resilient clean energy future. The proposal focuses on the 5-year and 10-year horizon, while also discussing the policy drivers and groundwork needed for future investments and alternatives in 2035-2050. While many of the proposals in the 5- to 10-year timeframe focus on utility assets that are specifically needed for near-term increases in demand, the Company envisions the 2035-2050 solutions set will integrate significant incentive design scenarios that will incorporate significant developments in DR, load management, and other aggregated or system-wide approaches. For all proposed investments and alternative approaches, the Company has identified 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 and air pollutants, avoided land use impacts and minimization or mitigation of impacts on the Company's customers. The Company also considers how the proposed investments will impact the workforce, the economy overall, and the population's health.

Section 3

Stakeholder Engagement

This section describes the Company's stakeholder engagement process to develop the Future Grid Plan, as well as the plan for future stakeholder engagement as the Company transitions from planning to implementation.

Key Take-Aways

- The Company is here to serve the communities where it operates the electric network, and it recognizes that building understanding and trust with all stakeholders (customers, communities, policymakers, public officials, and non-governmental organizations) is critical to a successful clean, fair, and affordable energy transition.
- Throughout the planning process the Company has engaged broadly and deeply — the Future Grid Plan reflects that engagement and involvement.
- In conjunction with the other EDCS, the Company has robust plans to continue this engagement so that it can make the investments and choices that its communities want and need.
- The Company is focused on ensuring that the clean energy transition benefits all, especially those communities which have historically experienced a disproportionate impact from the fossil-based economy.

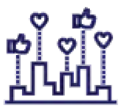
3.0 Stakeholder Engagement

Engaging and building understanding and trust with stakeholders is critical to achieving the Commonwealth's climate and clean energy goals. This includes engagement with customers, communities, policymakers, public officials, non-governmental organizations, and technology providers, among others; all of whom are both impacted by and important contributors to the fair, affordable, and clean energy transition.

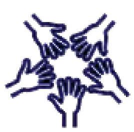
Stakeholder engagement is also paramount to the Company's ability to successfully develop and execute its Future Grid Plan. To ensure the necessary perspectives are gained to inform Future Grid investment plans, the Company is taking steps to identify, map, and understand the best ways to engage and communicate with stakeholders on an individual and collective basis. This includes leveraging available resources and forums, beginning with the GMAC, members of the public, and experts who have participated in the ESMP process thus far.

Additionally, the Company has conducted direct outreach to multiple stakeholders across the service area and throughout the Commonwealth. Plans are underway to do more, including conducting the technical stakeholder sessions required by *An Act to Drive Clean Energy and Offshore Wind* jointly with Eversource and Unitil. The technical sessions will be professionally facilitated by a third-party that will develop a report documenting stakeholder feedback to be submitted with the EDC's final ESMP submissions to the Department in January 2024.

Consistent with Eversource and Unitil, the Company's approach to stakeholder engagement is rooted in the following:



Building a shared understanding among stakeholders regarding the electric grid, the goals of electric sector modernization plans, and how these investments will help the Commonwealth meet its climate and clean energy goals.



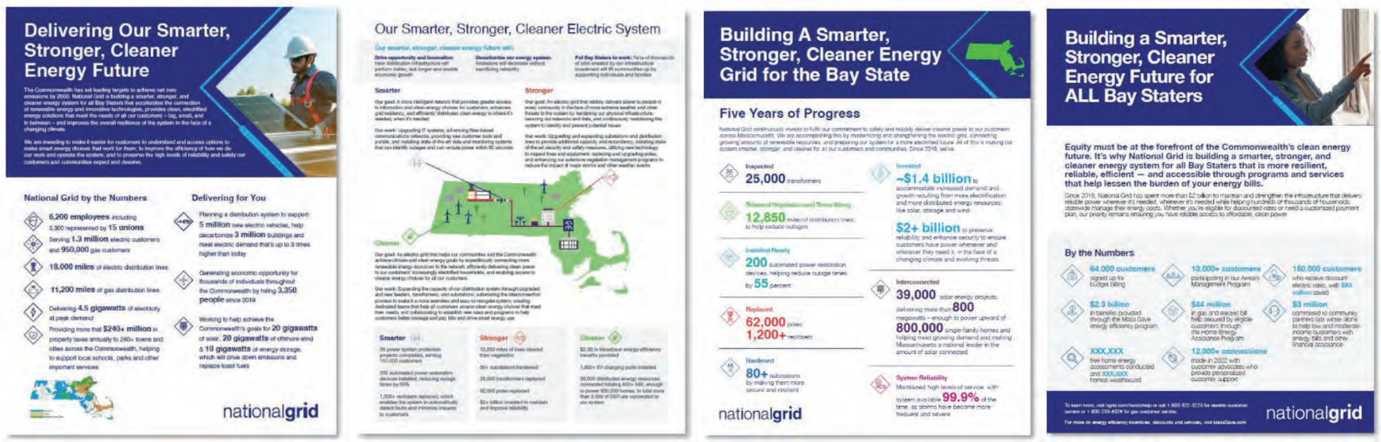
Developing collaboration by engaging stakeholders and establishing conversations to discuss the insights and initiatives required to deliver a smarter, stronger, and cleaner energy future and just transition, in ways that are relevant to them and meet community needs.

Tailoring outreach and stakeholder engagement plans to support local ESMP projects, elicit and incorporate customer feedback, and identify community concerns and needs. This will include a community-centric, culturally competent, and respectful approach to educate community members about the upgrades being made to the grid and the outcomes and tangible benefits they will deliver, and impacts.

The Company recognizes that as outreach is conducted, feedback received, and trust is sought, the Company must pursue engagement in ways that keep communications simple, relevant, and timely, and that are also inclusive, accessible, open, and collaborative.

To do this, direct dialogues and meetings are being held in both facilitated forums and one-on-one settings. Multiple and diverse communication channels are being leveraged through earned and paid media platforms, translating facts sheets and videos into multiple languages, and building digital tools such as websites and social content to provide all customers access to information about the ESMP process, the Company's plans, and ways to provide input.

Exhibit 3.1: Example of Future Grid Plan Stakeholder Materials



While the Company is broadly reaching out to multiple stakeholders, engagement is being emphasized with customers and communities that traditionally have not been fully or formally represented in proceedings at the Department or in processes like these (e.g., EJ and LMI communities and constituencies, municipalities, small businesses, labor).

In addition, the Company is leveraging existing data and customer research to better understand, across various customer segments, the outcomes Company customers want and concerns they have regarding the energy transition. This includes engaging with the Company's Customer Council (NGCC), which provides insights into customer needs and expectations that are helping the Company to make data-driven decisions.

In advance of this filing, to ensure that the submission being developed was taking into consideration the expectations, concerns, and needs of the Company's various stakeholders, extensive stakeholder outreach was conducted to build understanding of what the ESMP is, why it is being filed, and how stakeholders can engage in the process. To date, the Company has met with more than 20 municipalities, 10 business organizations and dozens of their members, representatives of EJCs, energy assistance providers, organizations representing generators, renewables, DER providers, EV providers and other technology providers, state officials, and housing developers.
A list of the stakeholders the Company has engaged is included in the Appendix.

As projects described in this ESMP move forward, the Company will work to ensure that there are significant energy and environmental benefits, with particular emphasis on electric service reliability, advancing clean energy, and reducing emissions, particularly in EJCs. Today, many EJCs in the Company's urban areas experience higher levels of reliability than other communities, resulting from underground distribution feeders and sufficient capacity at substations. However, other EJCs require investment to upgrade or expand electric infrastructure to increase grid reliability and increase hosting capacity, which will enable the connection and integration of more renewables and electrification in these areas. EJCs may particularly benefit from transportation electrification, which will have local air quality and health benefits. Proactively soliciting feedback and engaging communities in the decision-making process on ESMP projects will be paramount in ensuring successful outcomes.

As we work to advance a clean energy transition that centers around equity and EJ, the Company is focused on two key tenets when engaging with stakeholders and advancing investments and initiatives:

Procedural equity

To ensure that stakeholders and communities impacted by energy projects and programs are provided the necessary information and a meaningful opportunity to participate in and inform project development and implementation.

Distributional equity

To ensure that the clean energy transition is implemented in a way that drives equitable outcomes including the equitable realization of the benefits and burdens.

The Company has included in the Appendix a Draft Equity and Environmental Justice Policy and Stakeholder Engagement Framework to operationalize these tenets. This draft framework is *intended to articulate the Company's commitments to centering equity and environmental justice. The Framework builds on the Company's existing formalized outreach and engagement practices, and incorporates input received from EJ stakeholders to date and recommendations included in recent studies and reports published by EEA and the Attorney General's Office (AGO). This draft framework is being included with the Company's Future Grid Plan submission to the GMAC to solicit additional feedback prior to submitting with the final Future Grid Plan filing to the Department in January. The Company will also be engaging directly during this period with representatives of EJCs.*

Finally, the GMAC and its members have helped inform the Company's approach to stakeholder outreach and engagement and provided feedback on the Company's proposed approach and best practices from around the country.

Going forward, the Company will continue to leverage established communications channels, pursue direct engagement, and supplement this engagement with larger dialogues and meetings in both facilitated forums and one-on-one settings.

The Company is committed to doing things differently to make decisions collaboratively.
The remainder of this section provides additional detail on its outreach, education, and engagement strategies by stakeholder segment, key takeaways to date, and next steps.

National Grid Environmental Justice Policy and Engagement Framework

The Company's commitment to Company customers and communities begins by providing safe, reliable energy while transitioning to a cleaner energy future. To ensure reliable service, the Company invests in targeted infrastructure projects. The Company's public engagement team is committed to two-way communication in sharing information and addressing stakeholder concerns from the initial planning phases through construction and restoration. The Company is transparent throughout the lifecycle of projects by providing opportunities for stakeholders to connect with project teams, receive timely communication, and engage in the development and approval process.

The Company is developing an Equity and Environmental Justice Policy and Framework to ensure members of these communities are given a voice and agency with respect to the siting and other construction details of major infrastructure projects necessary to facilitate an equitable clean energy transition that is proposed in the Future Grid Plan. The Company's engagement with EJCs around major infrastructure projects that are part of the Future Grid Plan will also include consideration of the Company's workforce development programs. The Policy and Framework is informed by input from EJ organizations, which have provided valuable guidance on how best to communicate with historically marginalized communities. The Company will continue soliciting feedback as the Policy and Framework is refined and finalized, including from the GMAC and Equity Working Group.

The Company's stakeholder engagement efforts are guided by the following principles:

- **Collaboration.** Working with communities to build understanding of the investment options available. Without working together across all channels, success cannot be realized.

- **Communication.** Every day, the Company is building new avenues of outreach utilizing available tools – from traditional media, email alerts and in-bill messages, to door hangers, advertisements, texts and more – the goal is to reach every stakeholder where they are and in the language in which they are most comfortable communicating.

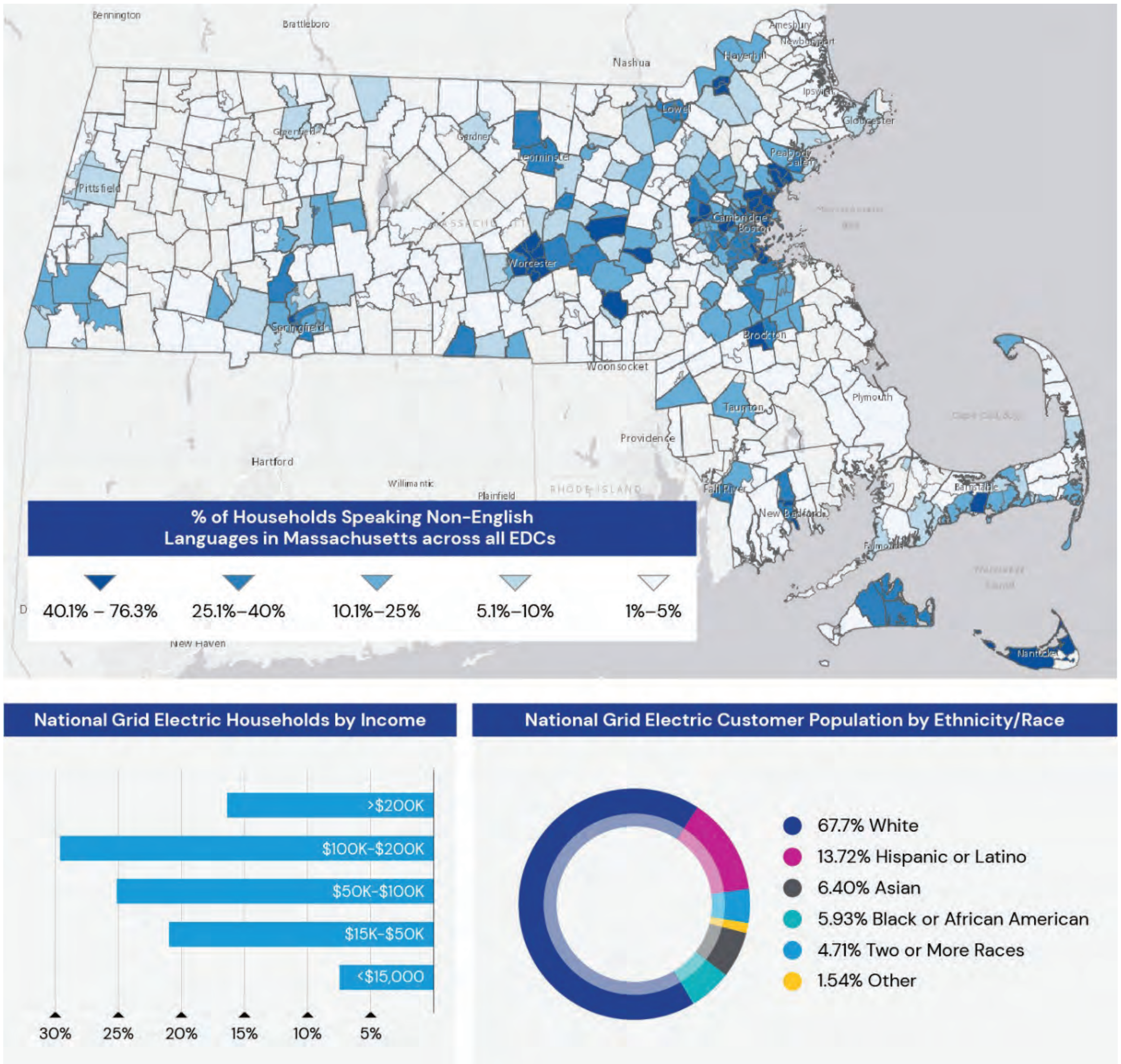
- **Incorporation of Feedback.** The Company is committed to not only soliciting input from stakeholders and customers but using that information to inform Company policies and projects, by bringing customers and communities in at the front end of decision making. The Company must be flexible enough to modify the approach as new information and feedback is available. It is critical that community members understand and have agency in the process, have avenues to make their opinions known, and – most importantly – see their input realized in Company policies and projects

- **Obtaining Equitable Outcomes.** Every community across the Commonwealth will require infrastructure investment in order to fully benefit from the clean energy transition. The Company is committed to ensuring that affected communities realize the benefit of Company projects, including health, equity, and economic benefits.

3.1 Customer Outreach

The Company's customers are extremely diverse and have varying levels of interest in and understanding of the clean energy transition, how they can participate in it, and what the benefits will be.

Exhibit 3.2: Customer demographics, including spoken language, household income and ethnicity/race



Company customers are also diverse in how they receive and consume information, and their channels of choice. Multiple methods are used to engage various customer segments, including earned and paid media, and using a diversity of media outlets, including those that target specific communities. The Company leverages social media and online platforms – including the website www.nationalgrid.com/ – weekly and daily newspapers, and radio. The Company's communications team has created a robust media plan that includes a mixture of paid placements and earned opportunities in a variety of online and traditional channels – including *The Boston Globe; CommonWealth Magazine*; the *Worcester Telegram*; and ethnic media, including, but not limited to *El Mundo; La Voz;* the *Bay State Banner;* and Telemundo/NBC Boston. The Company's goal is to reach the broadest possible audience to ensure they are educated, informed, and engaged in the state's clean energy transition and the Company's plan to help facilitate it.

In addition to general communications, the Company is working with business and community organizations and local chambers of commerce to connect with and engage with specific customer segments, such as retail, restaurants, academic institutions, non-profits, housing and commercial developers, and tailoring materials to make them relevant to these groups and their members to better elicit feedback. Finally, in-person events are being held to solicit input from Company customers. Feedback is also solicited through focus groups, customer satisfaction surveys, and targeted research to create a holistic perspective.

The Company also receives valuable input from the NGCC, which provides customer-driven insights that allow the Company to keep its finger on the pulse of customer needs and expectations. Members provide feedback on new product innovations, projects, and rate changes. The Company has been engaging with NGCC members to solicit important customer insights and concerns related to the investments needed to successfully reach the State's ambitious clean energy goals. Below are some examples of responses received:

- "Outage prevention would help everyone in the community significantly – especially during the winter months and extremely hot summer days."
- "All electric sounds great. However, the infrastructure must be there to support this. For example, we have an electric car. We also have a gas-powered car because we cannot rely on access to EV stations."
- "Robust and sustainable are two excellent worlds for what our power grid should look like. With a reliable power grid, we can all feel safer in our homes and workplaces. Progress (of the sustainable kind) will depend on a secure and available electrical supply."

3.2 Municipal Outreach

Engaging and deepening relationships with local leaders is a critical part of the ESMP process and essential for collaboratively and successfully executing the Company's Future Grid Plan. Local communities want to be a part of the decision-making process when choosing infrastructure locations. They want to understand the 'why' and 'what' and then be involved in the determination of the 'where' and 'how'.

The Company provides electric service to 168 of the 351 towns and cities in the Commonwealth. The infrastructure investment needed to reach clean energy goals will occur at the local level, which requires close coordination with local municipalities on community outreach and engagement around specific projects, obtaining local permits and permissions to do work in municipal rights of way and streets, and ensuring that construction timelines are such that they do not interfere with or complicate major municipal priorities, including the municipalities' own infrastructure work.

These same municipalities are also Company customers. Many have their own climate and clean energy goals, some of which have stated greenhouse gas reduction targets or detailed decarbonization plans. In addition to clean energy, local towns and cities have economic development goals and housing needs.

To better engage with and understand the interests of each town and city and their constituents, the Company is in direct dialogue with municipal leaders, including individual mayors and energy managers. The Company also engages with municipalities through organizations such as the Massachusetts Mayors Association and Massachusetts Municipal Association. In addition, direct outreach was conducted in advance of this filing to the towns and cities identified as having substantial infrastructure investment needs (e.g., expanded or new substations) included in the first 10 years of the Company's Future Grid Plan.

3.2.1 State Agency and Stakeholder Outreach

In recognition of the scale and importance of the State's clean energy goals, as well as the inaugural nature of the ESMP process, the Company has been assiduous throughout this effort in reaching out to pertinent state-level agencies, decision makers, and elected officials. The goal has been to ensure that the Company is on the right track with both its investment planning and outreach framework, with an eye toward minimizing customer impact while maximizing customers' ability to benefit from and participate in the clean energy transition. Meetings have taken place with the following:

- State AGO
- Massachusetts Department of Transportation (MassDOT)
- Executive Office of Economic Development
- Executive Office of Energy and Environment
- Office of Climate Change and Resilience
- Massachusetts Department of Labor

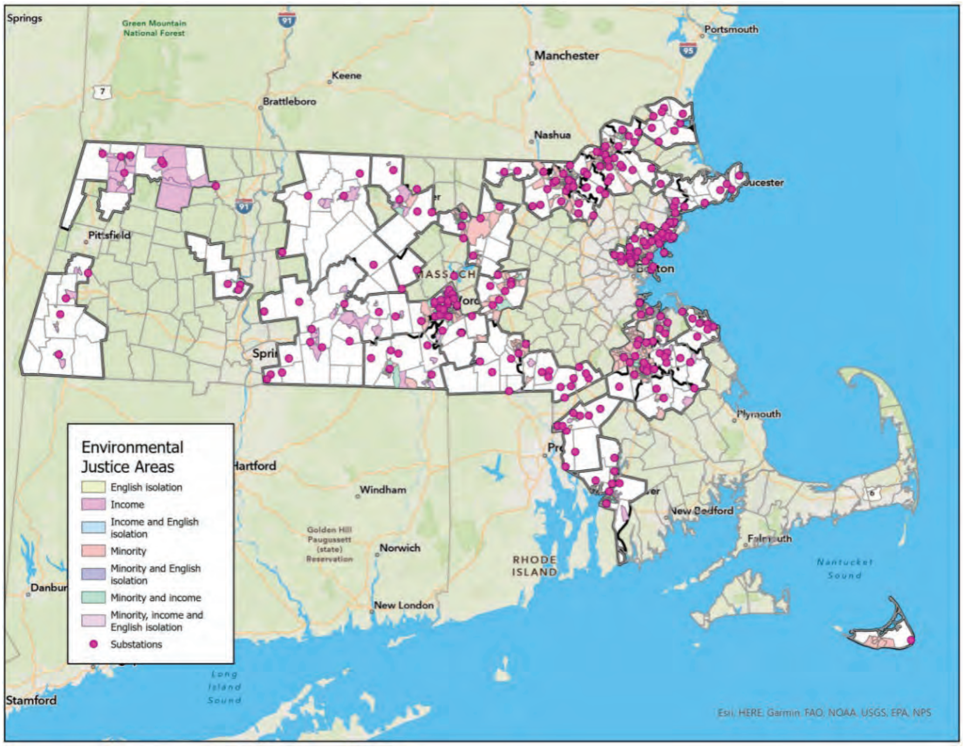
In addition to the above, the Company has engaged with the Department of Energy Resources (DOER) Commissioner's office, and with the chairs of legislative committees that oversee energy-related issues, who have interest in the ESMP filing and/or will take an active role in implementing and/or overseeing the clean energy transition.

This outreach is built upon the existing feedback and comments received via the members of the GMAC and the process for collecting public comments in these sessions. As of August 2023, the GMAC topics have included distribution planning, load forecasting, review of active EDC dockets, stakeholder engagement, equity, DER integration, and cost allocation.

3.3 Environmental Justice Community Outreach

The Company serves many gateway cities and communities throughout the Commonwealth, including Brockton, Quincy, Worcester, Lynn, Lowell, Lawrence, Haverhill, and North Adams. These towns and cities have large EJCs, as defined by the Commonwealth and identified in census data. The Company recognizes that a significant portion of Company customers live in EJCs, which are disbursed throughout the Company's service area, as shown in Exhibit 3.3 below.

Exhibit 3.3: Environmental Justice Areas



Earlier this year, the Company participated in a dialogue with a broad group of environmental and social justice stakeholders focused on energy equity and justice. Participants included those from labor, government, direct service and environmental organizations, energy advocates, technology providers, and representatives of academic institutions, among others. While this engagement was not specific to the Plan or ESMP process, it informed Company efforts to drive equity and address energy burden through current outreach and engagement efforts, elements of this Plan, and other actions the Company will be proposing as part of its rate review to be filed in November with the Department. In addition, the Company has also met with members of the EJ Table, both collectively and individually, the Office of Assistant Secretary for Environmental Justice at EEA, and municipal leaders that represent large EJ constituencies, and had an opportunity to participate in a recent Advanced Energy Group convening on equity and public health vis-a-vis grid modernization. The Company has also reviewed and considered feedback and recommendations included in both the Executive Office of Energy and Environmental Affairs, December 2022, *Clean Energy and Climate Plan for 2050* (CECP) and the Office of the Attorney General, May 4, 2023, *Group Convened by AG's Office Releases Recommendations to Improve Public Participation in Energy Proceedings.*

Within EJCs, there are customers that are low- and moderate-income, non-English speaking, new immigrants, and/or from minority populations. EJCs are not monolithic and the Company's approach to EJCs both as a whole and related to individual customer segments is intentional, tailored, and relevant.

LMI Communities: Low- and moderate-income energy customers in the Commonwealth face among the highest household energy burdens in the country, given the region's climate and energy prices. Today, approximately 475,000 Company customers qualify for some form of energy assistance. A wide range of assistance programs are available, but two key problems are apparent:

- *Low Enrollment*: Enrollment levels in programs vary widely, with the most well-subscribed programs reaching about one-third of eligible customers.
- *Inequitable Assistance*: The largest assistance program – the R-2 low-income rate structure – provides significant assistance but was not designed to equitably reduce energy burden.

In early 2022, the Company engaged E-Source, a research, consulting, and data science firm, to conduct an ethnography study to help develop a deeper understanding of the Company's LMI customers and to create a forward-thinking, multi-faceted customer experience strategy (see graphic below). Four customer cohorts emerged from the ethnography study. The study results provide important insights into the LMI customer segment. The Company learned that LMI customers both worry about their ability to pay their bills and are interested in making EE improvements, with overall bill affordability as their biggest driver.

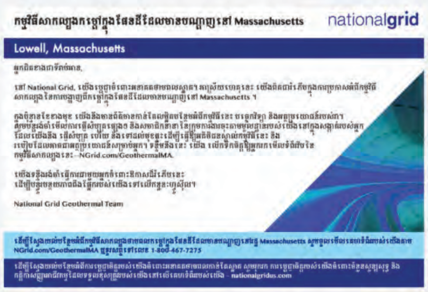
Exhibit 3.4: The Company's Customer Experience Strategy

The Company also reached out to AARP as part of its ESMP stakeholder engagement process to gain insights into the unique needs and circumstances of the energy burdened senior population.

Broad alignment and collaboration are needed to continue to advance and modify existing programs to increase enrollment and reduce energy burden, particularly for moderate income customers, that may not qualify under today's income-eligibility guidelines. The Company will be filing a proposal in the upcoming rate review filing to help address both energy burden and low enrollment, but more needs to be done both from a regulatory and policy change perspective.

While these proposals are pending, to reach eligible customers and raise awareness of available assistance and elicit feedback from these same communities on the energy transition, the Company will continue to work in partnership with energy assistance organizations including Community Action Program (CAP) partners, Community First partners, the AGO, and trusted nonprofits that reach these same populations, such as food banks and pantries and organizations that provide family support services. The Company will also continue direct engagement with municipalities that have high EJ populations including partnering to hold in-person Customer Energy Savings Events throughout the Commonwealth and use these events to educate these communities on the Company's Future Grid Plan.

Non-English-Speaking Communities: Roughly 23% of residents speak a language other than English at home. In the Company's service area, the communities with the highest representation of non-English speaking communities include Lawrence, Lynn, Revere, Southbridge, Everett, Methuen, Worcester, and Haverhill. Many non-English speakers are new immigrants, and thus have cultural norms and practices that may vary from the prevailing culture in the broader community, requiring different and culturally sensitive methods of engagement and outreach. A particular community's culture and background will influence the nature of the relationship both with the Company and to a particular project or program. Therefore, educational outreach and engagement must be language-friendly and mindful of cultural nuances. The Company will translate all pertinent publications – particularly related to affordability, energy conservation, and bill management - and identify and work with community members, leaders and third-party partners who are trusted organizations within these communities as the Company conducts its outreach.



For example, for the Geothermal Demonstration Program in Lowell, the Company recognized the importance of both using trusted voices and in-language communication to engage customers. Lowell is a diverse community with a large Cambodian population. To reach customers in the Geothermal Demonstration Program area, the Company partnered with the City of Lowell to conduct initial outreach and followed with a postcard mailing translated into four languages.

The postcard mailing was intentional, eliminating the need for an envelope, as concern was expressed that an envelope with a Company banner could be mistaken as collection activity.

Minority Populations: Approximately one-third of the State's residents are minorities. And, while some minorities are non-English speakers and/or new immigrants, many come from multi-generational families and have deep roots in their communities but may nonetheless receive information and respond to outreach via a defined subset of trusted voices and media outlets. Company outreach and engagement plans will be intentional in this respect, relying on trusted community partners, faith-based groups, individuals and targeted outlets, such as social media outlets, Google search & advertising, YouTube, targeted print media, and other media channels to reach individual customer segments and groups.

The Company recognizes that historically EJCs have borne the highest energy burdens and been disproportionately impacted by the fossil-based economy. As the Company prioritizes stakeholder engagement efforts, building relationships with EJCs will help ensure the equitable and successful implementation of the Future Grid Plan. As outlined earlier, a formal Equity and Environmental Justice Policy and Engagement Framework is being developed, as well as a complementary policy and framework focused on Indigenous Peoples. The Company will seek feedback from those communities prior to finalizing.

The Company's intent is to include these policies in the formal filing of this plan with the Department in January 2024. This is a top priority, and in recognition of the need to build and maintain these relationships, the Company plans to engage with these and other key stakeholders throughout the clean energy transition to ensure the Company remains responsive to challenges, needs, and concerns as they develop.

3.4 Stakeholder Meetings and Information Exchange

To date, the Company has held dozens of meetings specific to the ESMP process, touching hundreds of different stakeholders directly. These meetings have previewed the overall approach and elements of the Company's Future Grid Plan to elicit feedback on plan elements, overall areas and issues of need and concern related to the just energy transition, and to ask for assistance and ideas as to how to better reach and engage with customers, communities, and other stakeholders important to this process. The Company has also engaged with and received feedback on various plan elements, including stakeholder outreach and engagement, from members of the GMAC and public participants through that process. These meetings have been conducted both in person and virtually.

Going forward, meetings the Company has planned specific to the ESMP include:

- Two technical conferences to review the Company's proposed Future Grid Plan, held in coordination with Eversource and Unitil and professionally facilitated by a third party. These technical sessions will be targeted for November, recorded, and made available on the Company's website. The Company will also work with Eversource and Unitil to ensure the availability of translation services. (Please see Section 3.10 for additional details on these sessions.)
- Live and pre-recorded webinars that provide opportunities for the public and all stakeholders to submit questions and feedback.
- Sponsored forums, including those hosted by business organizations, local chambers, and news services.
- Legislative, agency, and municipal briefings.
- Participation in relevant conferences focused on clean energy and climate change.
- Hosted tables at local, in-person Customer Energy Savings Events, which are held in coordination with agencies and organizations that support the Company's LMI customers and communities, with a focus on EJCs. A listing can be found at www.ngrid.com/heretohelp.

3.5 Stakeholder Input and Tracking

The Company continues to identify and meet with stakeholders and track each engagement in a spreadsheet that enables us to capture feedback in real time. The spreadsheet is maintained by Company team members and shared with the broader team that has worked to develop the Future Grid Plan. As more engagements occur, including those specific to the Company's proposed Plan elements and projects, the tracking tool will be modified to classify comments and target areas of specific interest/concern by each stakeholder so areas of commonality and differences can be clearly identified across all stakeholders, by stakeholder grouping, and by geography. An online option for stakeholders to directly provide Plan feedback to the Company will also be available on the Company's website. Information collected through this portal will also be tracked in the tracking document.

Finally, as the Company transitions to implementing and executing the Future Grid Plan, broad engagement and direct outreach will occur to communities that the Company has identified as needing system upgrades in the next 10 years. The Company has a dedicated team that focuses on community and municipal outreach and engagement surrounding lager capital infrastructure projects. This team has an established process for education and engagement that aligns with the requirements of MEPA and which will be enhanced by the Equity and Environmental Justice Policy and Stakeholder Engagement Framework, once finalized and operationalized.

The Company is undergoing a review of that engagement process now and with the intent of making it more proactive, robust, and inclusive. The Company is also looking at best practice engagements, including the Company's approach to projects for which Infrastructure Investment and Jobs Act grants are being pursued. This includes Brayton Point and Twin States Clean Energy Link, and the Company's work on the Geothermal Demonstration Program in Lowell, and taking lessons learned from those engagements to better inform the stakeholder process going forward, with a particular focus on EJCs and how to develop community benefit plans collaboratively.

3.6 Key Takeaways from Stakeholder Engagement

The dialogue the Company has held with stakeholders to date has been robust and facilitated by a discussion presentation. The purpose of the engagement to date was to build understanding and begin to identify ways in which to develop collaboration channels going forward. Key takeaways from the stakeholder engagement the Company has undertaken to date include:

- **The importance of a deliberate transition.** Stakeholders emphasize the need to start engagement and planning with impacted communities and customers early in the process to ensure that concerns are being captured and addressed, and that agency is provided in siting decisions, coordinating work with municipalities and impacted customers, communities and neighborhoods, and identifying opportunities and avenues for partnership and shared benefits, particularly for those communities that will either continue to host significant energy infrastructure and/or are identified as needing new energy infrastructure investment. This includes working with trusted community partners throughout the process. Additionally, several municipalities viewed the clean energy transition as an opportunity to meet many of their own clean energy and economic development goals, by leveraging the proactive build out of the Company system to support municipal needs. For example, some municipalities are interested in creating electric-ready zones in their communities to attract new business. Similarly, the need for a deliberate transition was front-of-mind for Company labor partners. The Company works with 15 unions, both on the gas and electric side of its business. Issues related to training, workforce availability, and the need to maintain the safe and reliable operation of both systems were raised as paramount, with concern that these issues are not at the fore of policy and implementation discussions.

- **The need to maintain an affordable and reliable energy system.** Affordability and reliability are different goals, and each can mean different things depending on customer segment and economic circumstances. However, both are top of mind for many engaged stakeholders. The need to focus more holistically on overall energy burden and increase enrollment in existing affordability and assistance programs was raised several times, as well as the need for alternative rate structure and designs that can allow customers to better manage energy use and costs. In addition, engaged stakeholders expressed support for programs that provide value streams for various demand management and customer-owned solar and storage.[1] The vast majority of stakeholders focused on the need to ensure the system was resilient and able to respond quickly to any event, particularly as the economy becomes more electrified. Many stakeholders commented that current system reliability and storm response was good and wanted to ensure it was maintained through the transition. For businesses for which electricity is a critical input, such as healthcare and biotech, power quality was top-of-mind and system resilience and redundancy was paramount, as the cost of momentary outages, whether they are a few seconds or a few minutes, cause financial and operational challenges and risk.

[1] The Company will be proposing program and process changes in its upcoming Massachusetts Electric Company rate review filing to address this feedback as well as through the Mass Save 3-year program cycle review for 2025-2028.

- **The challenges customers and technology providers face challenges today to interconnect to the Company system timely and affordably.** Stakeholders emphasized the need to make it easier to do business with the Company. This issue was particularly acute with housing and commercial real-estate developers as well as DER providers. There is a recognition that the Company is working to shorten time frames, secure the necessary supply chain and make processes easier, but many stakeholders felt that more needs to be done, particularly as the pace of electrification and clean energy deployment accelerates, driven by policy and changes to building codes and standards, such as the Opt-In Municipal Stretch Codes and the prohibition on the sale of internal combustion engine vehicles by 2035. DER providers, housing developers, large customers and economic development-focused organizations want more timely and dynamic information on available grid capacity to host their projects, building off existing hosting capacity maps provided by the Company.

- **The benefits of Mass Save and the need for other programs that provide financial and technical support to pursue clean energy and energy efficient solutions.** Stakeholders also raised the need to expand those programs and make them more bespoke and targeted to individual customer segments and circumstances, including small business, commercial real estate, academic institutions, LMI customers, and municipalities. For example, many municipalities are concerned about the costs of the energy transition and ability to participate fully, not only for their own facilities, but also on behalf of their constituents. They are concerned about the challenges aging housing stock presents to weatherization and EE efforts, including retrofitting to install electrification technologies like heat pumps. Every municipality that is currently a participant in the Community First program raised the importance of the Mass Save program and the need to expand and increase funding for the program. Many municipalities also raised the need for additional support for fleet electrification, including technical support and support identifying and securing available state and federal grants to reduce the costs of the transition.

3.7 Future Stakeholder/Community Engagement Process (Forecasting, Solution Alternatives, Community Impacts)

Making initial contact with key stakeholders and the public was the first step in an ongoing process. The Company will continue to expand its connections throughout each community. As described in Section 3.6, additional stakeholder meetings are planned for the coming months.

The Company will further educate communities and stakeholders about the nuances of the ESMP and thought process regarding needs (e.g., new substations, miles of hardened distribution lines, and a variety of interconnections required to incorporate DERs into the grid). Company efforts will be informed by both its own Draft Equity and Environmental Justice Policy and Stakeholder Engagement Framework, as well as the Community Engagement Framework that will be jointly implemented with the other EDCs, per Section 3.10 below.

As the Company looks to how these investments will be made in the years ahead — to both fund and implement them — the Company fully understands the value of continuing engagement with customers and communities to ensure all residents understand how their energy system impacts them, and that the Company understands how to better serve them. Conversations are lengthy and substantive, and discussions are ongoing, but once the Company reaches a place of mutual understanding, it will be best positioned to work together to achieve the State's climate and clean energy goals while preserving reliability and keeping costs in check.

3.8 Ongoing and Newly Proposed Stakeholder Working Groups

The Company will continue to leverage existing groups and structures, including the Customer Council and DER collaboration groups such as the Technical Standards Review Group, Energy Storage Integration Review Group, and Interconnection Implementation Review Group and the EEAC Equity Working Group, as well as direct outreach to engage stakeholders and communities impacted by the clean energy transition, broadly, and the Future Grid Plan directly. The Company has several engagement events planned in the coming months, both as the Company and in coordination with the other EDCs.

For example, the Company and the other EDCs are committed to hosting two stakeholder workshops in the fall of 2023 as part of the ESMP filing process. Stakeholder engagement should be robust and proactively soliciting feedback is critical. The fall workshops will be conducted in the following manner:

- Stakeholder attendees will be pre-determined in consultation with the GMAC. (Note, members of the public will have the opportunity to provide public comment and feedback as part of the GMAC's two public comment listening sessions held in October, and the Company will continue to conduct outreach directly with a broad set of stakeholders throughout the service area.)
- Professionally facilitated
- Workshops will be hosted virtually, at times recommended by the GMAC or Equity Working Group, with language translation services
- Used as an opportunity to further educate stakeholders and gain feedback from the voices of the community.
- The EDCs, working with the facilitator, will track all recommendations and develop a formalized feedback loop for increased transparency
- All recommendations will be shared with the GMAC.

Proposed Community Engagement Stakeholder Advisory Group

In addition to the two fall stakeholder workshops, to further inform EDC engagement efforts around proposed projects from Section 6, the EDCs are proposing the development of a new **Community Engagement Stakeholder Advisory Group (CESAG)**. The CESAG will allow for a structured opportunity for the EDCs to develop a comprehensive community engagement and community benefits agreement frameworks that will a) enable increased transparency and stakeholder understanding of the complex electrical grid and EDC distribution planning process through establishment of a repeatable community engagement platform and b) ensure communities that host new substations and associated network infrastructure directly benefit from this clean energy enablement infrastructure. The CESAG will help to ensure that historical 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.

Members and Meeting Frequency:

- Composition of the CESAG members would be agreed upon by members of the GMAC but would be led by the EDCs, a set number of GMAC members, and community-based organizations.
- CESAG by-laws will be developed by the EDCs with input from the GMAC
- CESAG would begin meeting in February 2024 and meet two times per month for 4 months to develop the Community Engagement and Community Benefits Frameworks, finalized by the end of Q2 2024.
- Once the frameworks are established, periodic review of these frameworks would be conducted

- Frequency of future meetings would be determined by the CESAG as applicable
- Meetings will be professionally facilitated

Community Engagement Framework

To meet the objectives of the Commonwealth laid out in *An Act Driving Clean Energy and Offshore Win*d, as proposed in this Future Grid Plan, 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 CECP emission reduction targets. Given the need to execute all Department-approved ESMP-related projects – the Company's and those proposed by the other EDCs – the first mandate of the proposed 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 projects (from Section 6) going before the Energy Facilities Siting Board. This framework will be co-developed and informed by a partnership between the EDCs and key community-based organizations, and the Company's broader Equity and Environmental Justice Policy and Framework, as well as similar policies of Eversource and Unitil.

At their core, the EDCs are providers of safe and reliable energy. As the EDCs collectively continue to build and enhance their community engagement efforts, it is important the EDCs remain informed by the voices of their communities. This goal will be further supported 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, and which can be used to help the EDCs in efforts beyond ESMP-related projects.

The EDCs are not presuming the final outcome, but hope that the community engagement framework would enable the following:

- 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 trust and community engagement and/or participation.
- How input should be solicited and responded to
- 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.
- 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 understanding and engagement around projects in Section 6. This will help advance critical projects necessary as part of the ESMP to accelerate decarbonization in the Commonwealth. As the EDCs continue to learn and grow, the CESAG can continue to identify ways the EDCs can adjust outreach and engagement strategies in response to feedback from partners, allies, and communities.

Community Benefits Agreement Framework

To ensure that communities that host clean energy infrastructure directly benefit from the infrastructure, collaboratively designing and developing community benefits agreements between the EDCs and impacted communities is critical. Each community may have different needs and priorities, so presupposing what these agreements will include is premature. At the same time, having a framework and understanding the core elements to include will be helpful to ensure equity and consistency across the Commonwealth. Working with the CESAG stakeholders, such a community benefits agreement framework can take shape to ensure EDCs continue to re-think and formulate new methods and approaches to drive benefits from the just transition appropriate to each community.

Section 4

Current State of the Distribution System

This section provides a comprehensive overview of the state of the Company's electric distribution system today (i.e., the "starting point" upon which our proposed Future Grid Plan is built), including detailed reviews of the current state of the system by subregion.

Key Take-Aways

- We are at an inflection point. The period when the offsetting effects of the Commonwealth's nation-leading energy efficiency and solar programs has kept peak load growth flat is coming to an end. This period of stable peak load has limited the need to build out expanded system capacity to address load growth.
- During the last ten years Massachusetts has seen a rapid expansion in distributed solar and increasing energy storage deployment driven by the success of the Commonwealth policies. The Company's distribution network has become among the most densely DER-connected systems in the country.
- To plan and build the network needed, the Company runs a robust process to understand the localized conditions across the diverse parts of the Commonwealth that it serves, including asset conditions, DER adoption trends, demand growth, and customer needs.
- Through effective asset management practice the Company has been able to maximize the value from the existing assets, but the Company is now reaching a point where the existing network's capacity has been maximized. The Company must invest to provide more capacity to meet the needs of the clean energy transition.

4.0 Current State of The Distribution System

The purpose of this section is to provide a foundational understanding of the State of the Company's electric distribution network today, upon which the Company's proposed Future Grid Plan is built. This section will:

- Provide an overview of how the electric distribution network is designed and works,
- Outline the historical context on how the electric distribution network has been evolved over time to meet historical and current customer needs, and
- Explain how the electric distribution network is changing to address emerging customer needs.

This Section will also provide an in-depth review of specific aspects of the Company's electric distribution network, including information about the communities and territories served in the six planning sub-regions and the role the broader distribution utility plays in operating and maintaining the safety and reliability of this network. Finally, this section will explain how the technology systems in place today support the network and the Company's customers today and what must change to enable the Commonwealth's climate and clean energy goals as established in the CECP, while continuing to provide high levels of reliability and resilience as electrification and DER deployment accelerates and more of the economy is reliant on electricity as its primary fuel source.

4.1 State of the Distribution System and Challenges to Address

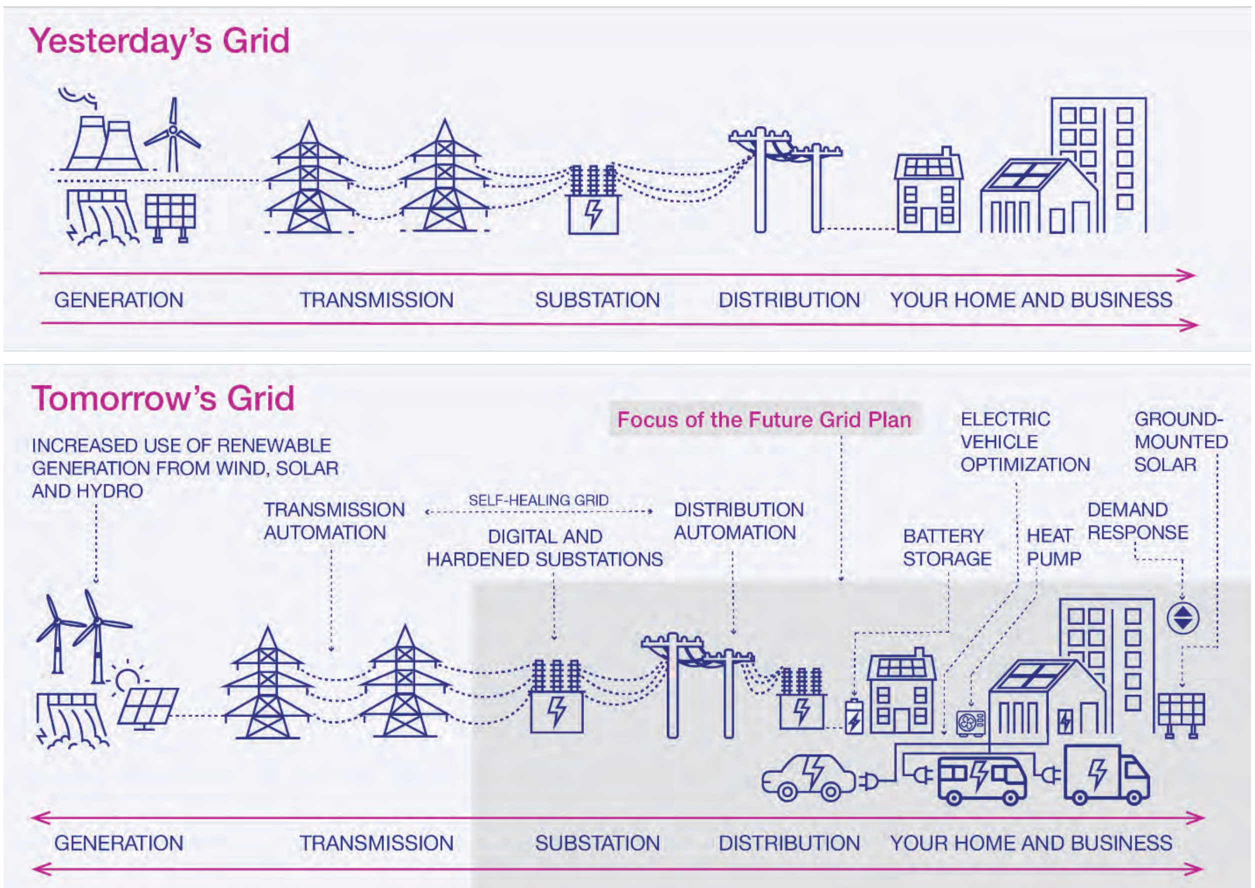
What is the distribution system?

An electric distribution system refers to the network of power lines, poles, substations, and other equipment that delivers electrical energy from the transmission system to end customers. It is the last leg of the journey of delivering electricity to homes, businesses, and other establishments from where it is produced to where it is consumed.

The distribution system differs from the transmission system in that it operates at lower voltages than the high-voltage transmission system, which is responsible for carrying electricity over long distances from power plants or generating stations, and typically carries this electricity shorter distances and to more end points. The primary function of the distribution system is to divide electrical power into smaller portions and distribute it efficiently to various consumers within a specific geographic area, such as a neighborhood or city. To provide a metaphor to the roads system, the transmission system can be thought of as the major highways of energy transport, whereas the distribution system is the network of public local roads. Like an "exit (or entrance) ramp," **substations** are where power steps down (or up) from one voltage to another. Substations are a critical component of electrical generation, transmission, and distribution systems. They are composed of an assortment of high voltage electrical equipment, including the "backbone" of the substation: the power transformer. **Transformers** either transform electrical energy from high to low voltage or from low to high voltage electricity. Transformers, and the associated primary electrical equipment within the substation, must have sufficient capacity to enable the two-way power flow from transmission and distribution (and vice versa). As the power flow of the network increases, the capacity of the substations must also increase to accommodate this growth. Substations also play a pivotal role stabilizing the network from abnormal events to improve reliability and safety. In the case of the distribution network, lower voltage electricity is distributed from the substation across a series of lower voltage **circuits** that lead to homes or businesses. These distribution circuits can run overhead or underground through rural or urban areas and provide electricity to various capacities of customers.

The Company's network has been built over the last 100 years primarily to facilitate the one-way flow of energy from large power generators on the transmission system down to individual customers on the Company's distribution network. However, with the increase of DERs such as distributed solar and energy storage over the last decade, the role of distribution is changing from one of strict delivery of power from a bulk power source to a system that exchanges power between various consumers and products on the distribution system. The structure typically involves multiple levels or components, each serving a specific purpose in the distribution process. Exhibit 4.1 below is a breakdown of the typical structure of the electric system. The section highlighted in grey shows the point from the transmission system down to a single customer meter. This is the part of the electric system that is operated by the Company and the focus of this Future Grid Plan.

Exhibit 4.1: Typical Structure of Electrical System



A brief history of the Company's distribution system

As the Company looks to plan the future electric distribution system to support the clean energy transformation, it is important to take stock of how the system has developed to date in the context of the regions and communities that the Company serves. The nature of electric service and the role of the distribution system infrastructure has been evolving since the origin of the electric grid in the Commonwealth in the early 1900s. Electric service was initially concentrated in industrial mill towns which were served by multiple individual power and light companies – many of which began as gas utilities prior to the invention of the light bulb and the displacement of gas lighting with electric lighting. Over time, the grid evolved to transport hydroelectric power from Vermont, New Hampshire, and western parts of the

State to serve industrial load centers, such as Millbury, Lawrence, and Worcester more efficiently. This commonly involved 69kv transmission being transformed at a local substation to a lower voltage of 4kV to support service to mills and surrounding communities.

In the early 1910s and 1920s, as electric lighting and industrial applications took hold and in the 1930s residential refrigeration and other appliances became commonplace. Electrification expanded rapidly through the 1940s. To support this growing demand, local electric companies typically overlayed their lower 4kV lines with higher 13kV voltage distribution lines, commonly leaving existing 4kV on their lower voltage lines given the cost of switching those customers. This “overlayed network” structure remains in many of these communities.

In the 1950s and 1960s, the electric systems continued to expand rapidly, fueled by significant economic growth. During this timeframe, many municipality-owned and small utilities consolidated into larger utilities. In 1962[1], Massachusetts Electric Company was established out of the consolidation of nearly 100 small companies, each serving a few towns. It remained relatively stable in size until 2000 when it grew once again with the merger of Eastern Utility Association.

This consolidation of separate utility systems means that today it is very common across the network to have similar but not identical voltage levels (e.g., 13.2 kV vs 13.8 kV), as well as the pattern of overlayed lines of differing voltages, as described above. A similar pattern occurred on the transmission system, with 69kV lines of the early century being overlayed by 115kV lines in 1930s and 1940s, followed by 345kV in the 1950s and 1960s.

Today, many of these early mill towns and load centers are also populated with numerous substations that emerged as the electric system evolved. Many of these communities that were the Company’s early source of distribution network growth contain populations recognized as Environmental Justice Communities (EJCs). Looking toward the future electric grid, the Company is mindful of the existing network’s footprint in some of these communities, as well as the broader economic and environmental challenges that these communities historically and continue to face. The Company is committed to giving these communities a voice as energy infrastructure projects that impact them are developed, and to addressing the challenges and barriers many of these same customers face when accessing clean energy solutions and affording their energy bills. Additional details on the Company’s approach to engagement and supporting EJCs is included in Section 3 and Section 9.

The Company’s distribution system today

As the primary electric provider for more than 165 towns and 3,870 square miles across the Commonwealth the Company provides service to approximately 1.3 million customer accounts, including approximately 1,138,090 residential households and 126,250 commercial and industrial (C&I) customers[2]. The Company’s network delivers nearly 4.7 GW of power to customers during the peak hour of the year.

The Company delivers safe and reliable service to customers through an integrated system that includes 178 substations and connects customers through a network of 1,146 circuits of both overhead and underground construction that span more than 18,500 miles. The Company’s network primarily consists of 4kV and 15kV[3] class distribution circuits. The distribution system also includes a modest amount of higher voltage sub-transmission, including 156 overhead and underground circuits of 23kV and 46 kV supply lines spanning more than 655 miles.

The Company has successfully interconnected approximately 2.2 GW of DERs across the State which includes solar, batteries, wind, hydro and others, while interconnection requests continue to increase. For example, today, there are more than 2 GW of applications in queue, of which 66% are standalone energy storage facilities and 29% are solar generation – basically doubling the capacity of what is currently connected to the Company’s distribution system. The Company’s distribution network also currently

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[1] From the Rivers, the Origins and Growth of the New England Electric System, John T Landry and Jeffrey L Cuikshank, page 172, 1996

[2] There are many dual account customers (both residential & C&I) that conflate the number of customer accounts.

[3] 15kV class includes voltages such as 13.2kV and 13.8kV.

supports the electrical load from more than 32,000 EVs and 10,000 EHPs, which represents ~1% of total vehicles and less than 1% of customer heating systems. Connections of these end use technologies are expected to increase considerably over the next decade as customers adopt electric transportation and electric heating at a scale described in Section 5, per the Commonwealth's goals.

The Company's network is supported by nation-leading Energy Efficiency and Demand Response (DR) programs through Mass Save, which saved customers billions of dollars and avoided the release of thousands of tons of greenhouse gases to the atmosphere. These programs have also resulted in a peak demand reduction of 30% or 1.3 GW, keeping load growth relatively flat over the past decade and allowing the Company to avoid or defer some investments in system expansions and upgrades.

Harnessing the Power of Flexible Demand

Largely through the offsetting effects of the Commonwealth's nation-leading EE programs, for the last 15 years, the Company has kept peak demand relatively flat (see section 5) and avoided investments in network capacity that would otherwise have been needed. In the period of 2013-2022 alone, the Company estimates that its EE programs have saved customers over $800m in distribution infrastructure costs. The Company believes that continued EE programs and new approaches to flexible demand will continue to play a critical role in reducing the cost of the energy transition.

What is flexible demand?

Beyond traditional EE, flexible demand includes measures such as DR programs and time-varying rates (TVR) that can incentivize flexible loads like ESS, controllable thermostats, and EV charging to shift load away from one time of the day (i.e., when the network is constrained at peak) to another time of the day (i.e., when the network is not peaking). The Company today offers several flexible demand programs including its ConnectedSolutions DR programs and its EV off-peak charging rebate program.

Why is flexible demand important?

The Company plans its network to ensure safe and reliable operation in all hours of the year with particular focus on the peak load. Flexible demand can help offset future peak load growth (by smoothing out the use of electricity) and thereby reduce, defer and sometimes avoid the need for some of the investment required in network infrastructure. Flexible demand is more important than ever considering:

1. **Growing demand**. Electricity demand is expected to grow considerably over the next 5 and 10 years, primarily due to EVs and EHPs, which will require significant investment in the electricity network.
2. **More flexible devices**. More and more flexible devices are connecting to the network, meaning there is greater potential to leverage these devices to help manage the grid and to compensate customers for offering their flexibility services.

continued on next page >

How is the Company advancing EE and flexible demand capabilities over the five-year investment period?

The Company sees tremendous opportunity to further leverage EE and flexible demand. Over the five-year investment period the Company will scale existing initiatives, and propose new programs, policies, and investments to increase the reliance on flexible demand as a resource. A key theme will be scaling existing system-wide programs and developing new capabilities to deploy more targeted programs based on specific network and customer needs.

Summary of Proposed Investments and Programs to Expand EE and Flexible Demand over next Five Years

	Scale Existing	Deliver In-Flight	Deploy New (via ESMP or related filing)
Customer Programs	• EE • System Peak DR (curtailment, ESS, controllable thermostats, EVs) • Off-peak managed EV charging	• ARI for solar (flexible connections pilot)	• Targeted EE • Targeted DR • TVR • Virtual Power Plant (VPP) • Flexibility Market • Scale flexible connections for EVs and ESS
Enabling Technology		• AMI • ADMS • DERMs (pre-authorized)	• DERMs (expanded features) • Supporting data, security, and communications

As the Company's capabilities mature over time and the Company also learns about customer adoption and behaviors, the Company will modify its forecasts to reflect the expanded role of flexible demand, and the Company will integrate flexible load to offset network investments and help address operational needs.

Further, as discussed in section 6, every effort will be made to ensure that all customers have the ability to participate in flexible demand programs and enjoy the savings, including expansive customer education and outreach and scaling of proven and tailored programs designed for EJ and LMI customers.

The next phase of the distribution system's evolution will be driven by the need to be ready to enable and accommodate significant new load resulting from the electrification of transportation and heating. A key element of enabling an affordable clean energy transition will be encouraging efficient use of the network to avoid the need for excess new system capacity and customer costs. There is an opportunity to reflect on lessons learned, while also utilizing technologies enabled by a Distributed Energy Resource Management System (DERMS) such as active resource integration (ARI) to manage this new load and ensure a more optimal and efficient expansion of the system. Technologies such as AMI, when paired with more dynamic price signals will also help directly engage customers in managing demand to encourage efficient use of system infrastructure and avoid unnecessary system growth. As these technologies are integrated into the system, the Company recognizes the need for ongoing customer outreach and support, particularly for LMI and EJC customers.

The Company's role as the distribution utility

As electric network operator and provider of electricity for the communities served, it is the Company's job to facilitate the planning, construction, operation, maintenance, and restoration of the electric network to fulfill the Company's mission and obligation to provide safe and reliable electric power to all customers. The Company operates and is responsible for making prudent investments in the infrastructure network that transmits energy from where it is generated to where it is consumed – the Company does not own the actual power plants that produce this energy nor does the Company profit from the sale of this electricity. The Company also provides direct customer services, such as metering, billing, and administering various State-approved programs, including Energy Efficiency, EVs, and solar. A brief description of a subset of these functions can be found below.

- **Planning**: The Company makes important decisions about how to most prudently serve its customers safely and reliability while maintaining affordable service every day. The planning function involves conducting the underlying analysis and making decisions about the best way to meet the needs of customers either through maintaining existing equipment, investing in new infrastructure or by adopting new and innovative non-infrastructure approaches (e.g. non-wires alternative [NWA]). Deteriorating Equipment due to aging or weathering (i.e., "asset condition") may need to be replaced; broken equipment (I.e., "damage failure") must be repaired; new commercial facilities or solar projects (i.e., "customer work") must be connected to the network; emerging trends in customer outages within specific areas (i.e., "reliability") must be addressed, and expanding and/or upgrading the network to accommodate expected growth in electrical load over time (i.e., "system capacity") must occur.
- **Project delivery**: This is the function where the Company delivers the investments in the plans. This can include conducting more-specific site engineering and design, acquiring necessary real estate and permits, evaluating environmental conditions, securing materials, resources, staffing and deploying construction crews to implement the work, and integrating the site with the broader network. The Company delivers dozens of multi-million-dollar projects each year. As an example, a new substation takes, on average, 5-7 years to build from start to finish with 20+ project team members resourced.
- **Operations**: Field operations are responsible for the physical management of the electrical grid, including onsite supervision and hands-on maintenance of electrical infrastructure (e.g., substations and power lines), and integration of new or updated infrastructure into the network system. Field operations is also responsible for responding to storms to repair damaged or broken equipment as quickly and safely as possible. Control center operations monitors and manages the network 24/7/365 and has real-time visibility into network conditions to dispatch assets and field operations crews as needed in response to grid conditions. This includes coordinating outage response, implementing switching orders, and scheduling any necessary system reconfigurations or outages to safely facilitate planned maintenance. All operations work is done with a commitment to and responsibility for the safety of the public and the Company's employees.
- **Metering and billing**: As the distribution utility, the Company operates the network that brings electricity down from the high voltage transmission system right to customers' homes and businesses. At each customer's premises, the Company meters the amount of energy delivered to (or exported by) customers so that they receive bills based on the energy that they consume (and/or produce). This metering function is served for traditional load customers and DERs that export energy onto the grid (e.g., solar).
- **Program administration**: The Company is the program administrator for numerous statewide incentive programs that deliver additional value to customers, including those related to Energy Efficiency, DR, electric heat pumps, EVs, solar, and more. The Company is committed to making participation in the clean energy transformation easy and effortless for customers, and to help them enroll in opportunities to lower their electric bill.

Emerging challenges on the Company's distribution system

The role of the distribution utility and the challenges to the distribution network are changing considerably.

While investments to maintain the network to ensure the safe and reliable operation of the Company's existing assets continue to be made, the needs of customers are shifting, and the Company's network investment and operation is changing to reflect these shifts.

The Company continues to face challenges that are common across all large-scale utilities such as:

- **Aging infrastructure**: Aging equipment, such as transformers, switchgear, and power lines, can lead to increased outage risks and decreased system efficiency as their condition worsens. Upgrading and modernizing legacy and decades-old infrastructure is a significant expense due to the cost and complexity involved.
- **Voltage management/Power Quality**: Maintaining appropriate voltage levels and power quality is crucial for the distribution grid's reliable and efficient operation. High load conditions cause voltage to decrease, and high generation causes voltage to increase. Introducing generation throughout the distribution system, particularly intermittent generation (e.g., solar, wind), impacts the voltage profile often in unpredictable ways. Voltage fluctuations, harmonics, and other power quality issues can lead to equipment malfunction, reduced efficiency, and potential damage to consumer devices. This is particularly acute for customers with sensitive advanced manufacturing equipment, life sciences and biomedical research laboratories.
- **Resiliency**: Distribution grids are vulnerable to various disruptions, including extreme weather events, natural disasters, and cyberattacks. These threats continue to evolve, and consequences are impactful as electrification accelerates and new devices are added to the system. Additionally, bad actors are becoming more sophisticated and weather unpredictable. This involves increased levels of investment in software, hardware and infrastructure to protect, isolate and restore systems.

These challenges are heightened, and their implications are amplified by the imminent clean energy transformation and changing customer expectations and needs, including:

- **Connecting renewables**: In recent years, the Company has implemented significant amounts of customer-driven network investment to support the connection of thousands of distribution-connected renewable projects like solar and energy storage. The State has the second largest amount of solar per square mile in the country (0.5 MW/mi^2) and the Company holds the largest share of solar in the State. Continued investment in the Company's networks is necessary to ensure that more renewables can sufficiently be accommodated and can direct that energy from remote locations to the densely populated metropolitan regions where electric load is concentrated. Innovative ways to accelerate the interconnection process will continue to be developed so that timely network access is ensured, including investing in smart grid solutions to accommodate renewable energy integration effectively and to manage its variability.
- **Increased load from electrifying heat and transport**: As the Company will cover in more detail in sections 5 and 8 and more broadly throughout this Future Grid Plan, the rapid expected electric load growth due to the adoption of electric transportation and heating will also drive a shift from the Company's present summer peaking network to one that will be winter peaking in the late 2030's. The growth in electricity consumption from electric transport and heating in particular will need to be met by timely delivery of expanded electric system capacity on both the distribution and transmission networks. If timely investments are not made, the existing infrastructure will become overloaded. This can result in:

1. Asset damage and / or premature ageing. Equipment is assigned ratings that specify how much load it can carry without accelerating loss of life, incurring damage, and/or creating unsafe operating conditions. Exceeding these ratings by "overloading" equipment, even for short periods of time, can result in premature asset failures. Load relief projects, like those in this plan, are designed to add new or upgrade existing equipment in order to create the system capacity required to meet projected demand without incurring overloads.
2. Inability to manage contingencies. If multiple assets in a given area are heavily loaded (even within their ratings), a failure of one asset can result in significant outages for customers because the remaining operable equipment in the area does not have spare or "contingency" capacity to serve the customers who would normally be served by the out of service equipment.

There are standards and procedures to abate these technical issues, but as more load comes onto the system, more infrastructure will be required. To meet the increased loading, areas of the network where lower voltages were historically used, such as 4.16 kV, may need to be converted to higher voltages such as 13.2kV or 13.8 kV. Similarly, substations will need to be upgraded with additional or expanded transformer capacity to accommodate future load growth. As the needs and interests of customers change, the Company will need to continue adapt the design and capacity of the electric network.

- **Accelerating timely adoption of customer clean energy technologies and delivering customer-driven programs**: In addition to building out the network capacity to support the connection of renewables and adoption of EVs and electric heating, the Company has increased emphasis on facilitating and administering programs that help customers adopt clean energy technologies. To deliver on the State clean energy goals, the Company will need to continue to implement and accelerate their various incentive programs and information campaigns related to Energy Efficiency, EHPs, EVs, and DR.

Fast Charging – Fleets & Highways

Highway fast-charging and electrification of fleets are critical to meet the Commonwealth's transportation electrification goals. These two decarbonization solutions have unique challenges that the Company is well positioned to address. Executing early on these plans is critical to meet customers' needs as they arise rather than in a reactionary fashion.

1. Highway charging infrastructure

What is highway charging infrastructure and what challenges does it bring?
Highway service plazas, truck stops, and similar sites present specific challenges because of their unique characteristics.

- **Customers need fast charging at a time that suits them**. Unlike home charging, drivers at highway rest stops do not have the flexibility to change their charging behavior.
- **Large "net new" electrical loads (see chart below)**. To provide fast charging at these sites is comparable to the electrical load from a new sports stadium or a small town, and often requires new grid infrastructure.

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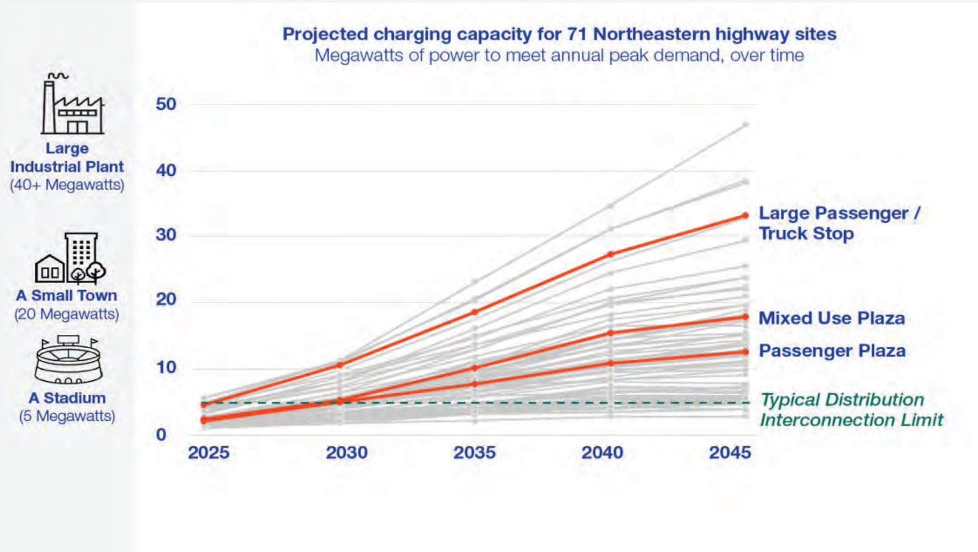

Source: *NG EV Highway Study*[4]

The grid infrastructure for these sites can take years to design, permit, construct, and energize which can be longer than delivering the chargers themselves, and typically cannot start until a customer requests service. The Company needs to act now to make sure the network is ready in time.

How is the Company accelerating deployment of Highway charging infrastructure?

a. **EV Charging programs**. The Company currently supports customers who wish to build on-highway and highway-adjacent EV charging projects through its EV charging programs, which include:

- **Make-ready incentives** to help defray costs to allow for more charging projects and/or stretch customers' budget further.
- **Demand Charge Alternative** for EV fast charging projects, including those on highways, to reduce customers' operating costs of EV chargers by providing discounts on their demand charges in the early years when their stations see inconsistent or low utilization.

b. **Industry-leading studies**. The Company previously released its Electric Highways Study, which provides key insight on the electric loading potential from highway charging and suggests ways to best support highway charging infrastructure.

c. **Expanding network infrastructure**. Section 6 of this Future Grid Plan includes three proposed substations to support EV highway charging located at various plazas (Charlton, Bridgewater, and Westborough). All substations are projected to be in-service by 2034.

d. **Stakeholder Engagement**

- The Company is engaging with stakeholders like MassDOT on other potential projects, to develop an integrated plan on the optimal timing and locations to enable highway charging.

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[4] *(https://www.nationalgrid.com/us/EVhighway*

- The Company was awarded a grant by the U.S. Department of Energy to study freight corridor charging needs in more detail across the Northeast and develop a regional plan for implementation.[5] This study will be completed in mid-2025.

2. Fleet electrification

What is fleet electrification and what are some of the challenges?

The Commonwealth's ambitious transportation electrification policies mean that over time, fleet owners will transition their fleets to EVs. Forecasting exactly where and when such large spot loads from fleet charging will materialize is a new challenge. The Company is exploring new methodologies to identify spot loads in demand forecasting to help prioritize network capacity increases.

How is the Company accelerating deployment of fleet electrification?

a. **EV Fleet Programs**. The Company is collaborating with fleet owners through several EV program offerings including:
    i. EV charging make-ready support tailored to fleets, including providing fleet advisory services to help fleet owners with their electrification plans.
    ii. Managed charging programs to incentivize fleet operators to charge their vehicles at off-peak times and reduce their charging costs.
    iii. EV DR through the ConnectedSolutions program, to allow operators to earn value for their flexibility, including Vehicle-to-Grid (V2G) services.

b. **Flexible connections**. As described in Section 6, the Company is developing a flexible interconnection program for fleet customers so they can connect to the grid before all network constraints are resolved.

c. **Industry-leading studies**. The Company partnered on a 2021 study with Hitachi Energy to understand the impacts of fleet electrification on the network.[6] A follow-up study with detailed system impacts, illustrative solutions, and implications will be released Fall 2023.

d. **Expanding network capacity.** The Company's forecast includes projected demand from fleet electrification, and the incremental network infrastructure investments proposed in the Future Grid plan will support this forecasted demand. The Company will continue to explore ways to improve forecasting methodologies, and early identification of potential fleet electrification spot loads and refine its capital investment plan on those future forecasts.

e. **EJC Programs**. The Company will support electrification of fleets operating in EJCs that historically have experienced a disproportionate share of environmental impacts from the transportation sector, including local air pollution. This includes school buses, public transit, and public or private fleets operating in, or depoted in, those communities.

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[5] https://www.energy.gov/articles/biden-harris-administration-announces-funding-zero-emission-medium-and-heavy-duty-vehicle

[6] https://www.nationalgridus.com/media/pdfs/microsites/ev-fleet-program/understandinggridimpactsofelectricfleets.pdf

- **Increasing network resilience**: Climate change can lead to more frequent and severe weather, resulting in high winds, snowstorms, icing events, and river and coastal flooding, all of which pose risks to grid infrastructure. As society electrifies, the economy and way of life will be increasingly dependent upon the grid. As more customers adopt EVs, electric heating, and embrace working from home, customers will need even more confidence that their electric network access is secure and reliable. There has also been an increased threat from "bad actors" who wish to disrupt the network, a risk that is increased by the need to develop a more sophisticated and connected network with larger volumes of shared data. Ensuring grid resilience involves hardening infrastructure, implementing redundant systems, enhancing cybersecurity measures, and establishing robust emergency response plans.
- **Improving flexibility of network Operations and Management (O&M)**: As DER adoption and EVs, electric heat pumps become more widespread, the Company will need to plan and operate a more complex network. For instance, solar variability can create power quality and grid reliability issues. Battery storage can create fluctuation issues as it can rapidly shift from acting as a load (charging the batteries) to acting as a generator (discharging the batteries). Without direct utility management to integrate these DER facilities into the grid, utilities are left with the challenge of managing unpredictable DER activity, and DER customers are left with high grid expansion costs to accommodate all operating conditions. The Company is actively investing in data capabilities and control system centralization including an Advanced Distribution Management System (ADMS) and developing flexible connections solutions, such as ARI, both of which will be discussed in section 6, to improve the ability to operate and manage the network.

As will be discussed in the coming sections, addressing these challenges requires collaboration among utilities, policymakers, technology providers, and other stakeholders, as well as continued investment in grid modernization to make it ready and maintain reliability, improved data analytics, advanced monitoring and control systems, and enhanced communication infrastructure to building more resilient, efficient, and flexible distribution grids.

Promoting Energy Storage

The Company shares the Commonwealth's vision that energy storage will play a critical role in the clean energy transition.

What is energy storage?

Energy storage systems (ESS) refer to technologies that convert electrical energy from power systems into a form that can be stored for converting back to electrical energy when needed. Battery energy storage is a prominent ESS example. In recent years, the Company has seen a sharp rise in distribution network interconnection requests for ESS, including those that are designed as large standalone systems, co-located with other renewables, or configured BTM at customer homes and businesses.

ESS are highly flexible, meaning they can operate as a load (drawing electricity from the grid for storage, such as to charge a battery) or generator (exporting electricity onto the grid, such as discharging a battery) at any given time, and can transition rapidly back and forth between load and generation. This can present both opportunities and challenges.

What are some of the opportunities for energy storage?

ESS can function as a "Swiss army knife" for the network and customers when deployed tactically and operated reliably. ESS can:

- Replace fossil-based peaking plants by shifting energy production from intermittent renewables to be used to supply load at peak

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- Defer or avoid network investment or reduce overloading risk on the transmission or distribution networks by alleviating network constraints as NWAs
- Help individual customers save money on their bill via participation in DR programs, or to help reduce demand charges for large commercial and industrial customers
- Provide backup power in the event of an outage
- Provide ancillary services helping to balance frequency and voltage

What are some of the challenges in integrating energy storage?

- **Interconnection**: For ESS to connect to the network via a standard, unconstrained interconnection service agreement, there needs to be sufficient system capacity during all hours for the storage to be either a load or a generator on the network at any time. For large ESS in particular, this often results in a complicated study process and the interconnection may require costly network upgrades similar to a large spot load.
- **Siting and operations**: Current ESS incentives are not necessarily resulting in storage deploying in locations or operating in ways that would be most helpful to resolve distribution network constraints.

How does the Company's Future Grid Plan help to address energy storage?

The Company is actively addressing these challenges by offering new solutions as part of this Future Grid Plan so that the system and the Company's customers can more fully leverage the benefits of energy storage.

- **Scaling flexible connections**[7]: Building from the ARI pilots, the DERMs phase II investments will allow flexible connections to be deployed at scale for DER, including ESS. This will help improve the costly and lengthy interconnection process via reliable and secure implementation of utility-controlled curtailment to reduce the amount of new headroom needed to support a storage interconnection.
- **Create opportunities**: New opportunities for storage developers to earn value are being created by:
    - Scaling the existing ConnectedSolutions DR programs, which already include storage
    - Procuring grid services via new NWA demonstration projects
    - Enabling new opportunities for ESS to earn value in the wholesale markets via FERC Order 2222

In addition, the Company is also developing retail and wholesale tariffs for ESS.[8,9]

4.2 Planning Sub-Regions

The Company's territory spans the State, serving a diverse range of geographies including rural communities in the mountainous western part of the State, densely populated urban communities

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[7] See: https://gridforce.my.site.com/s/article/ACTIVE-RESOURCE-INTEGRATION-ARI-FLEXIBLE-INTERCONNECTIONS-PILOT

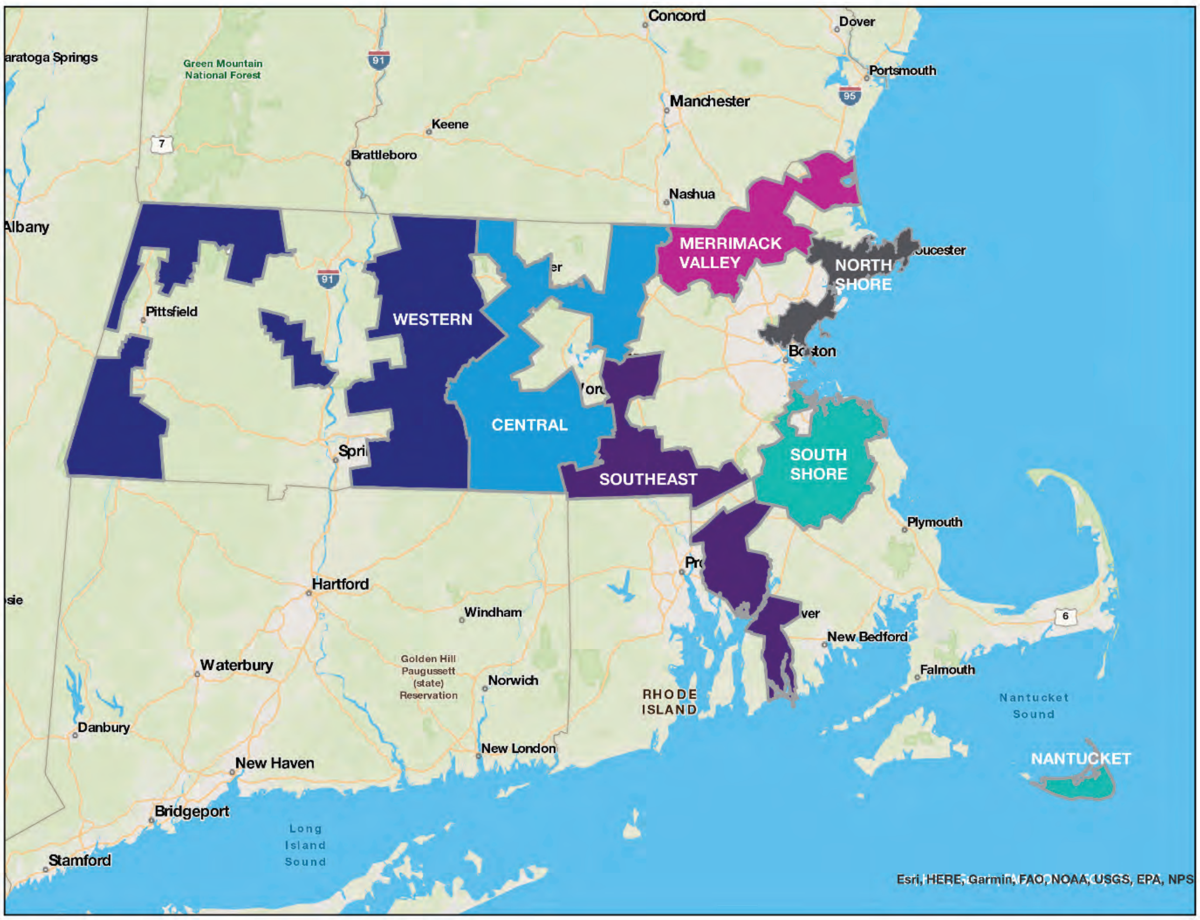
[8] Outside of this Future Grid Plan, the Company will file with the Department by October 31, 2023, an ESS electric retail rate tariff which addresses operational parameters, in compliance with the 2022 Climate Act, Section 72

[9] The Company also will file with FERC by October 31, 2023, a notice of intent to promptly file with FERC a wholesale distribution service rate schedule applicable to standalone ESS connected to the Company's distribution network but transacting in ISO-NE wholesale markets, in compliance with the 2022 Climate Act, Section 72.

in Worcester and Brockton, suburban communities across the Merrimack valley, and coastal communities along the North and South Shore. As discussed throughout this Future Grid Plan, each of these territories have unique physical, economic, demographic and historical characteristics that impact each location's electrical network design and shape the challenges ahead associated with readying that section of the network for the clean energy transition.

For purposes of this Future Grid Plan, the Company has organized the Commonwealth territory into six operating sub-regions: Western, Central, Southeast, South Shore (including Nantucket Electric), Merrimack Valley, and North Shore. These regions are summarized in Exhibit 4.3 below.

Exhibit 4.2: National Grid's Six Major Service sub-regions



The sub-region groupings are based on both geographic proximity and electrical system characteristics, including distribution design elements such as operating voltages and substations (e.g., two feeders connected to the same substation would be in the same sub-regions). The Company has on-the-ground support in each of the sub-regions including office locations, line crews, metering personnel, customer and community managers, and distribution system engineers.

For planning and conducting underlying engineering analysis for the distribution system, the Company further divides its distribution system into 46 study areas, which are defined based on electrical interdependencies. Each of the sub-regions contains several study areas. The study areas are summarized in Exhibit 4.3 below:

Exhibit 4.3: Distribution Study Areas

Sub-regions and Towns					
Central	**Merrimack Valley**	**North Shore**	**Southeast**	**South Shore**	**Western**
Ayer Clinton	Amesbury Newburyport	Beverly	Attleboro	Bridgewater	Adams/Deerfield
Gardner Winchendon	Billerica	Cape Ann	Fall River	Brockton	Barre-Athol
Leominster	Chelmsford Westford	Everett Malden Medford	Hopedale East	Brockton NW / Randolph	Monson-Palmer-Longmeadow
Millbury-Grafton	Dracut	Lynn	Hopedale West	Hanover	Northampton-S Berkshire
Pepperell Dunstable	Haverhill	Melrose Saugus	Marlboro	Nantucket	
Spencer-Rutland	Lawrence	Revere Winthrop	Somerset	Quincy	
Webster Southbridge Charlton	Lowell	Salem Swampscott		Scituate	
Worcester North	Methuen	Topsfield		Weymouth Holbrook	
Worcester South	North Andover				
	North Lowell				
	Tewksbury				

Exhibit 4.4 below summarizes key characteristics of each sub-region. Note that the below DER values represent total nameplate capacity (i.e., maximum rated potential of total DER). These numbers do not reflect firm power generation capabilities due to the intermittent nature of DER technologies which does not provide a constant, reliable energy source comparable to the utility power source.

“Pending DER” in exhibit 4.4 below outlines the DER in the interconnection queue, which is dynamic. Based on historical queue progression, only about 60% of the pending DER projects progress through to interconnection into the system. The projects that do not end up getting built are limited by a variety of factors some of which may be project financials, siting and permitting, or offtake roadblocks. The Company does not forecast specific large load or large DER connections and does not proactively invest in the network to connect these loads since they only invest when the DER signs an Interconnection Service Agreement (ISA). What is included in the forecast, discussed in Section 5, is the expected introduction of DER as part of the overall planning process.

Exhibit 4.4: Key Characteristics of Each Sub-Region

	Central	Merrimack Valley	North Shore	Southeast	South Shore	Western
Customers	241,061	263,871	255,067	231,799	239,140	121,606
Feeders	247	297	319	178	187	90
Substations	46	58	49	43	39	29
DER Penetration	High	Medium	Low	High	Medium	High
Connected DER (MW)	631.5	266.6	152.2	425.6	218.6	521.2
Pending DER (MW)	542.6	256.2	77.5	440.8	255.4	431.2
Peak Load 2023 (MW)	943	1,212	1,107	1,029	938	418

4.3 Central Sub-Region

The Central sub-region in brief:

Nature of the area: The Central sub-region is predominantly suburban, with regional urban centers in Gardner, Leominster, Clinton, Southbridge, Webster, and Worcester. With a population of slightly more than 200,000, Worcester is the largest city the Company's electric business serves in the State.

The Company's customers' energy needs, economic circumstances, and demographics in the Central sub-region vary greatly, which is why targeted and culturally competent community engagement is at the core of the Company's plan to help the State achieve its goals.

Exhibit 4.5: Central sub-region customers by the numbers

Total Customers (Accounts)	% Residential	% Business, Commercial, Municipal, or University	Benefits of EE	Heat Pump Adoption (end of 2022)	Total NG Charging Ports Installed
241,061	87%	13%	1,216,250 MWh	4,184	291 Ports

Exhibit 4.6: Central sub-region network by the numbers

Number of Substations	Number of Feeders	Total Length of Feeders	Total Peak Load Served	Square Miles of Sub-region
46	247	3,750 miles	943 MW	875

Context of the region

The Central sub-region includes the Company's largest cities, which have a highly integrated network, as well as a substantial number of rural areas, which have a more radial network.

The Central sub-region has high levels of DER penetration relative to all other sub-regions due to the large amount of open space coupled with a more robust distribution infrastructure as compared to the western area of the Commonwealth. Due to the large population center of Worcester and growing suburban areas, the Company anticipates load to grow by approximately 10.2% in the Central sub-region in the next 5 years. Additional details can be found in Section 5.

Below are some key characteristics of the Central sub-region which will drive future investment needs.

Exhibit 4.7: Central Sub-Region Key Characteristics that will Drive Future Investment Needs

Network Characteristic	Consequence
The majority of the distribution circuits are 15 kV class circuits, which operate at voltages of 13.2 kV or 13.8 kV. There are eighty circuits that operate at 4.16 kV which primarily supply downtown Worcester and are supplied from substations that step down the voltage of 13 kV to supply customers. Lower voltages such as 4.16 kV were used more commonly in the past when loads were lower.	Areas served by these lower voltages will largely need to be converted to a higher voltage such as 13.2 kV or 13.8 kV in order to meet the significant load growth that is projected across the State. Voltage conversions can be costly and complex projects, requiring widescale replacement or upgrade of significant amounts of both distribution line and substation facilities.
The 23 kV class subtransmission circuits act both as supplies to substations and to serve mostly larger load customers.	Subtransmission circuits have less capacity than transmission circuits; therefore, load growth on subtransmission-supplied substations can sometimes be limited by the subtransmission feeder supplying it. As a result, the Company will need to invest in both upgrading the substation and the supplying feeder. These types of supply considerations might be less concerning than if the substation were supplied from a transmission (i.e., 69 kV and higher) voltage.
A 1902 Worcester Bylaw prohibited overhead wires within a 2-mile radius of Worcester City Hall. The Company's solution to this was to install overhead facilities in customers' "backyards," with underground cable and switches in the public way.	Feeders will need to be rerouted out of customers' backyards. The *Underground Bylaw* means the Company must pursue underground solutions for any infrastructure development in this area.

4.3.1 Maps

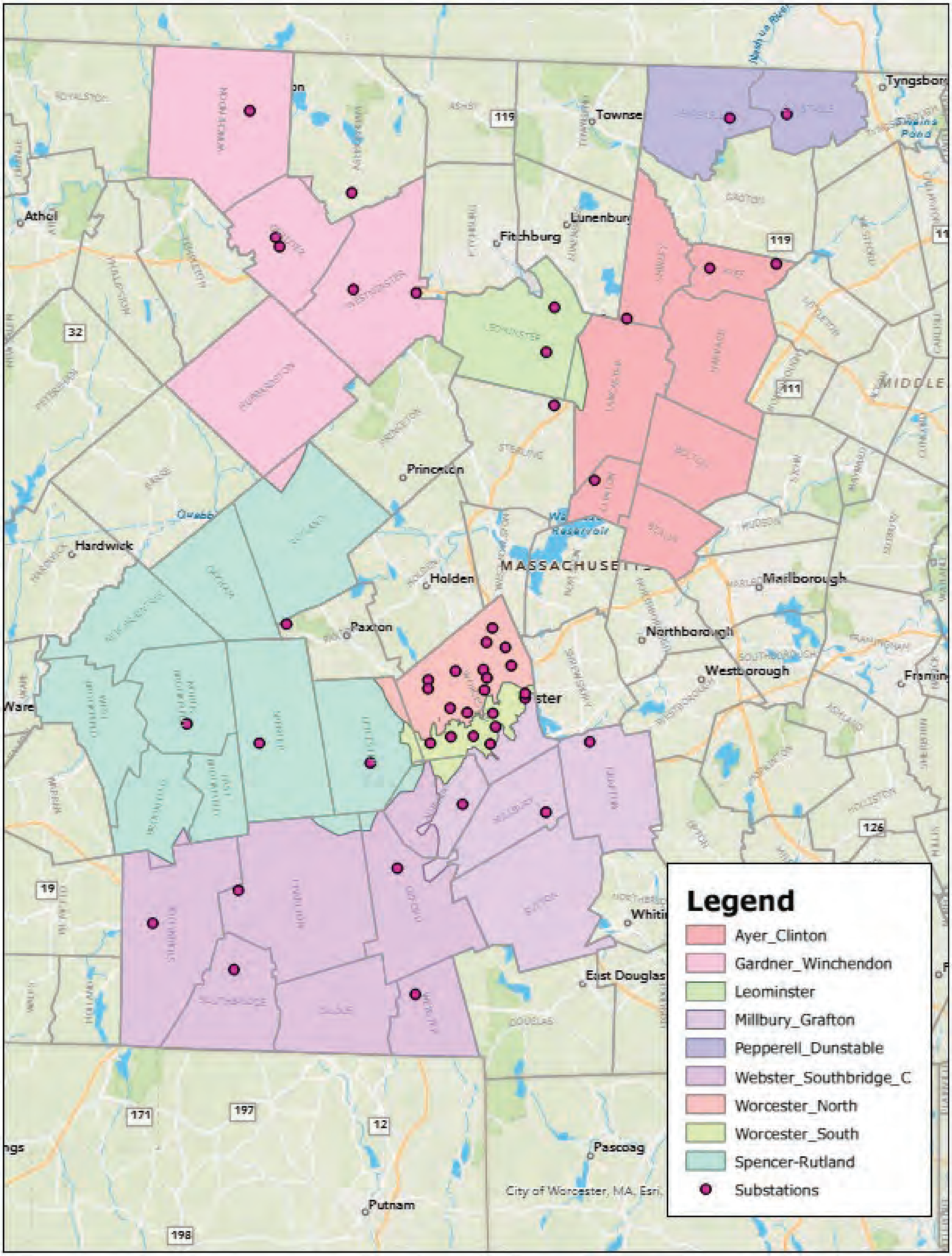
The Central sub-region consists of 33 towns and cities and comprises the study areas below.

Exhibit 4.8: Central Sub-Region Study Areas and Towns

	Study Area	Town
1	Ayer/Clinton	Ayer, Berlin, Bolton, Clinton, Harvard, Lancaster, Shirley
2	Gardner/Winchendon	Gardner, Hubbardston, Rutland, Westminster, Winchendon
3	Leominster	Lancaster, Leominster
4	Millbury/Grafton	Auburn, Grafton, Millbury, Oxford, Sutton, Worcester
5	Pepperell/Dunstable	Dunstable, Pepperell
6	Spencer/Rutland	Auburn, Brookfield, Charlton, East Brookfield, Leicester, north Brookfield, Oakham, Oxford, Rutland, Spencer, West Brookfield
7	Webster/Southbridge/Charlton	Auburn, Brookfield, Charlton, Dudley, Oxford, Southbridge, Sturbridge, Webster
8	Worcester North	Leicester, Worcester
9	Worcester South	Auburn, Leicester, Worcester

Exhibit 4.9 below shows the substation locations within the Central sub-region's study areas, indicated with a red dot. Not all study areas cleanly follow town lines because they are defined electrically instead of geographically. Many of the locations of substations in the Central sub-region were driven by the need provide electricity to the mills that existed in the early and mid- 20th century, which were located along the rivers.

Exhibit 4.9: Central sub-region Substation Locations and Study Areas



4.3.2 Customer Demographics

Exhibit 4.10: Central sub-region customer demographics summary

Number of Customers				Residential Population Growth	Benefits of EE	Existing Connected Rooftop DER (< 25kW)
Total	Residential – Total	Residential – Low Income Rate Participants	Commercial	5-year Growth Projections		
241,061	241,061	31,821	31,457	2%	1,216,250 MWh	100 MW

The Company serves a total of 241,061 customers (defined by individual accounts, not the number of people served) – in the Central sub-region. Approximately 87% (209,604) of these customers are residential customers and the other 13% are comprised of commercial, municipal, or university customers.

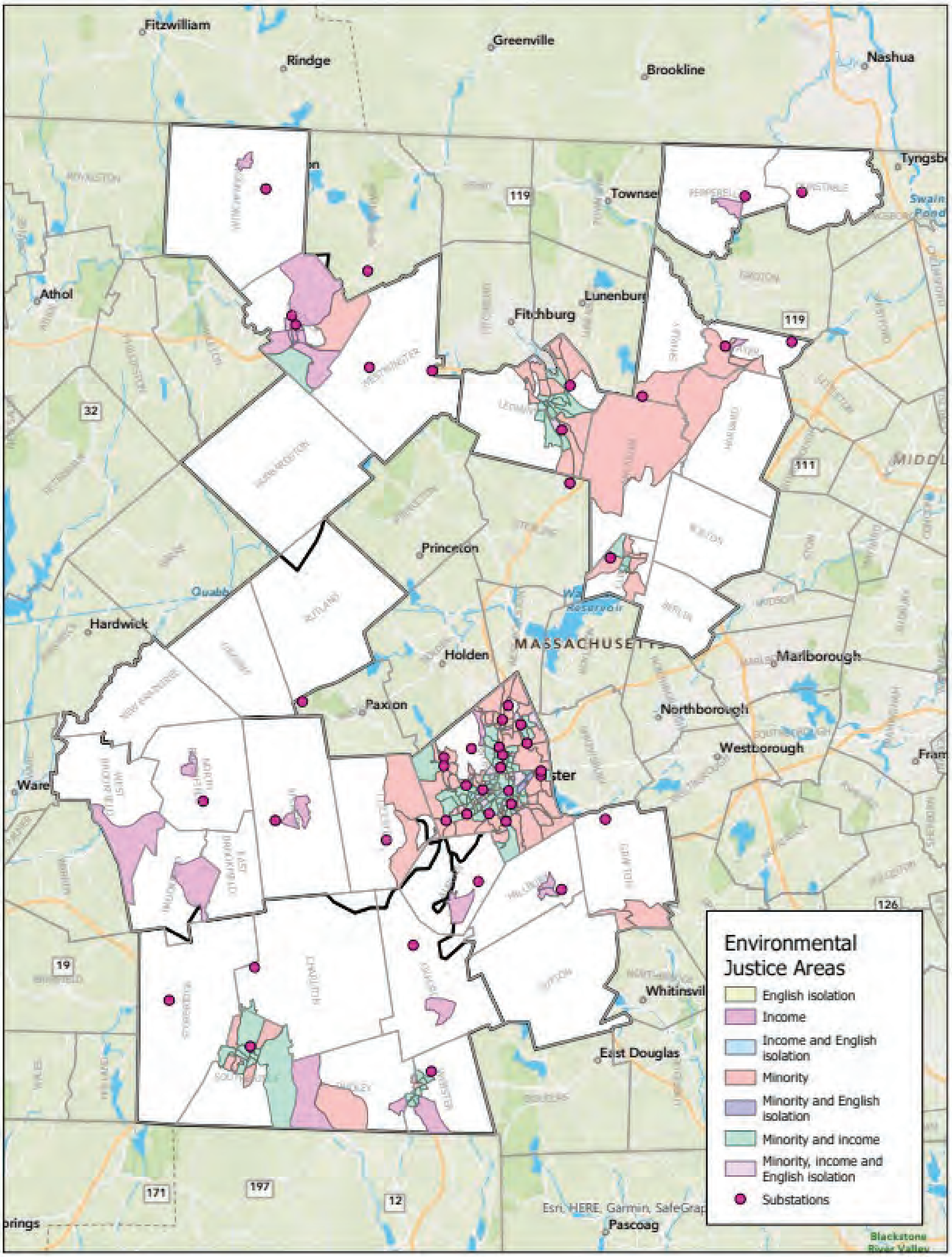
In addition to the Mass Save programs, which have benefited customers in the Central sub-region, 24 towns statewide have been identified for targeted outreach per the Massachusetts Energy Efficiency Advisory Council (MA EEAC) Equity Working Group plans. Under these outreach plans, the Company is specifically working to encourage more Energy Efficiency benefits in low-adoption zones. The towns/cities included in the Central sub-region are Worcester, Southbridge, and Gardner.

The Company recognizes that a significant portion of the Company's customers live in EJCs, which are disbursed throughout the Company's service area. Historically, EJCs have borne the highest energy burdens and been disproportionately impacted by the fossil-based economy. As outlined earlier in Section 3.3, the Company is developing a formal Equity and Environmental Justice Policy and Engagement Framework, as well as complementary policy and framework focused on Indigenous Peoples, which the Company will seek feedback on from those communities prior to finalizing, please refer to the Appendix for those drafts.

Below please see Exhibit 4.11 below which overlays the Commonwealth Environmental Justice Population map with the Company's current substations.[10] Exhibit 4.11 highlights the concentration of substations in many load-dense areas – Worcester, town centers, and other major economic areas with industry. Load density and electric capacity needs are the key drivers to substation density and location. As the load increases, the need for more substations to serve these population centers and expanding rural areas will increase too. Many EJCs have been identified as such by the Commonwealth because they have been historically unduly burdened by infrastructure and related pollution. As discussed in Section 3, the Company is committed to being a trusted partner with all the Company's host communities, including those which contain EJCs, as new infrastructure needs to be built throughout the Commonwealth to reach decarbonization and electrification goals. Additional infrastructure that has yet to be built per recommendations in this Future Grid Plan can be found in Section 6.

[10] Multiple substations in close proximity with one another may appear to be overlapping or as one dot on this map

Exhibit 4.11: Central sub-region substations with to the Commonwealth's EJC map



4.3.3 Economic Development

The development of the Company's Plan was informed, in part, by the varying levels of readiness within each sub-region. Within the Company's study areas defined in the Future Grid Plan, 14 communities have completed decarbonization plans and 139 are designated as "green communities" under M.G.L. c. 25A §10. In partnership with the Company, the following municipalities have completed a Strategic Energy Management Plan (SEMP): Athol, Beverly, Everett, Lowell, Melrose, Newburyport, and Salem. The Company anticipates one new SEMP to be signed before the end of the year, with an additional five SEMPs in the development queue.

In the Central sub-region, two communities (Harvard and Worcester) have completed decarbonization plans and 29 are designated as green communities. While economic development strategies vary within the sub-region, the most recent Comprehensive Economic Development Strategies (CEDS) conducted by the Worcester Regional Chamber of Commerce highlights the importance of continuously identifying available and/or underutilized sites and buildings to promote development that increases access to transportation and strengthens utility and telecommunication infrastructure capacity. The CEDS conducted by North Central Massachusetts Chamber of Commerce identifies several industries for retention and development, including advance manufacturing, health care, logistics and distribution, and tourism and small business.

4.3.4 Electrification Growth

Heat Electrification - The Central sub-region has the highest heat pump adoption among the six sub-regions. Approximately 3,000 units have been adopted as of the end of 2022, of which nearly 80% are hybrid.

Transport Electrification – There has been steady growth in the LDEV sales in the Central sub-region with about 3,700 vehicles as of the end of 2022. However, the total number of MHDEVs is less than 10 indicating very low penetration at present. Since 2019, The Company has installed 291 EV charging ports via their phase I and phase II EV charging programs in the Central sub-region.

4.3.5 DER Adoption (Battery Storage and Solar Photovoltaic)

With a total of 566 MW of generation connected, the Central sub-region has high DER penetration, representing about 25% of the total DER in the Company's Commonwealth jurisdiction, nearly all of which has been connected in the last decade. Based on national average data, this amount of DER is enough to power nearly 100,000 homes[11].

Exhibit 4.12: Central sub-region DER adoption summary

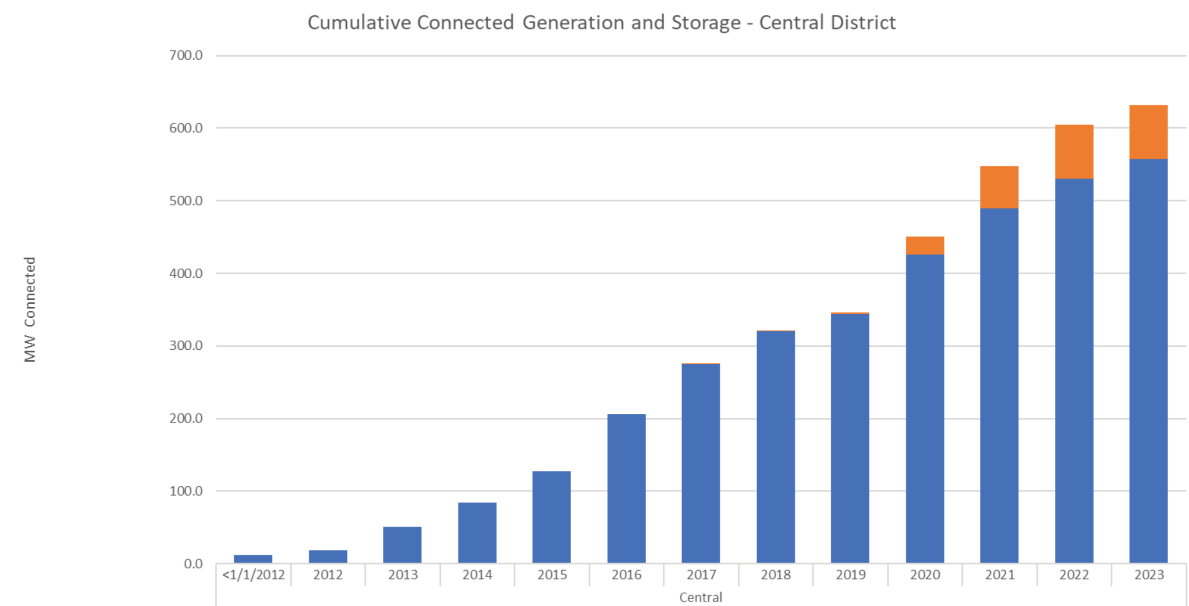
Sub-Region	Solar (MW)	Battery (MW)	Hydro (MW)	Wind (MW)	Miscellaneous (MW)[12]	Grand Total (MW)
Central – Connected DER	502.4	74.7	3.1	0.8	50.5	631.5

[11] According to the Solar Energy Industry Association, the national average for national average (through Q2 2022) of homes powered by a MW of solar is 173. https://www.seia.org/initiatives/whats-megawatt#:~:text=The%20current%20national%20average%20(through,MW%20of%20solar%20is%20173.

[12] "Miscellaneous" encompasses fuel sources including bio gas, diesel, fuel oil, hydrogen, landfill gas, natural gas, and propane.

Note that in Exhibit 4.13 below, the 2023 value is reflective of cumulative interconnections as of July 2023.

Exhibit 4.13: Central sub-region Cumulative Connected Generation and Storage



	<1/1/2012	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Sum of Total Storage MW	0.0	0.0	0.0	0.0	0.0	0.0	0.5	1.1	1.3	25.0	57.7	74.1	74.7
Sum of Total Generator MW	11.8	19.0	50.7	84.2	127.3	206.3	275.6	320.7	344.4	425.9	489.6	530.6	556.8

Exhibit 4.14 below shows the current DER interconnection queue in the Central sub-region as of July 2023. Overall, within the queue, Solar Photovoltaic (PV) represents 45% and batteries represent 54% of the current queued DER capacity. Recent application trends have demonstrated a shift from largely solar PV applications to a split between solar PV and battery storage.

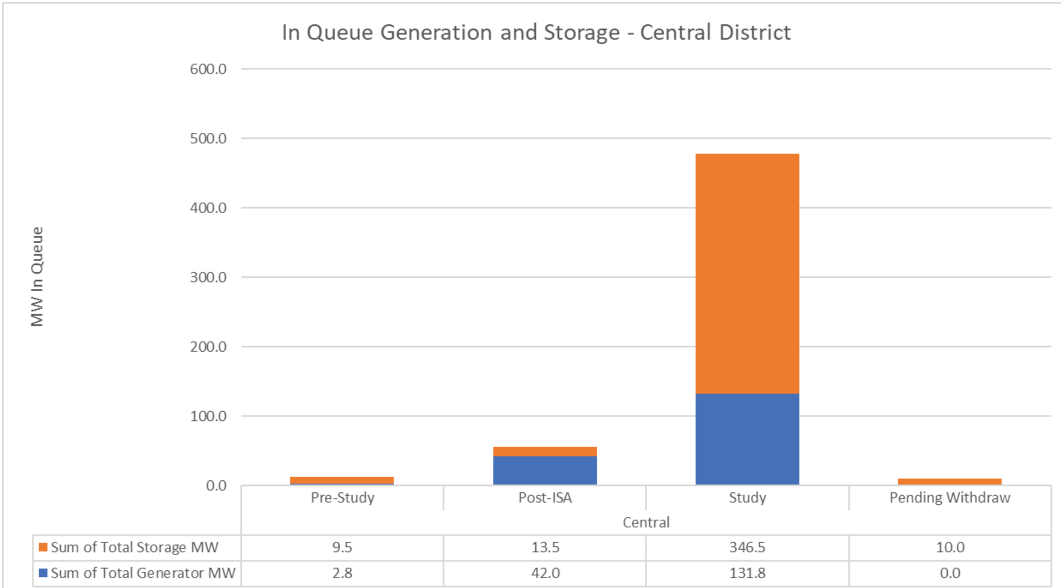
A large majority of the batteries are stand-alone, albeit some are co-located as PV paired with storage. Unlike other forms of DER, which operate solely in a discharge or export capacity, contributing power to the grid, standalone batteries also must charge from the grid. While solar and other forms of DER, excluding batteries, only require there to be sufficient grid hosting capacity for their interconnection, batteries require both hosting and load-serving capacity at the location of their interconnection. Therefore, batteries are subject to capacity deficiency, charge, considerations such as those highlighted in Section 4.3.7 as well as any hosting capacity, discharge, constraints that may be present.

This significantly increases the complexity of planning and operating the network.

Exhibit 4.14: Central sub-region pending DER summary in queue

Sub-Region	Solar (MW)	Battery (MW)	Hydro (MW)	Wind (MW)	Miscellaneous[2] (MW)	Grand Total (MW)
Central – Pending DER	155.5	379.6	3.5	0.0	4.1	542.6

Exhibit 4.15: *Central sub-region* pending DER Generation and Storage in queue



Combining the 542.6MW of DER in the interconnection queue, and the 631.5MW already connected in the Central sub-region, the total for the area would be 1,174W if all in-queue projects move forward. While it is unlikely that all will connect, this would be a doubling of interconnected DER in an already constrained area and would therefore require significant infrastructure expansion. Layering on the complexity of battery operation and solar variability, advanced grid management tools will be necessary in addition to the infrastructure build out to maintain the safety and reliability of the grid.

There are Capital Investment Project (CIP) proceedings underway in this area under the following dockets:

- Gardner Winchendon (Department Docket No. 23-06)
- Spencer Rutland (Department Docket No. 23-09)

In the Central sub-region, the Company has analysis completed or is in progress for a group study for the interconnection of DER in the following study areas[13]:

- Ayer-Clinton
- Millbury-Grafton
- Webster-Southbridge-Charlton
- Leominster
- Worcester North and South

The proposed DER and system modifications required for the proposed groups have been included in the base case for the Future Grid Plan analysis; should the DER customers in these groups not proceed to interconnection, the investments described in this Future Grid Plan will need to be analyzed for the impacts of this attrition and adjusted appropriately. The Company is proposing to apply CIP cost allocation principles to these investments once they reach sufficient maturity.

[13] Only those areas of sufficient maturity for inclusion in the base case of this Future Grid Plan analysis are indicated here. Therefore, this is not a comprehensive list of all areas in which the Company has ongoing group study process.

The high-level benefits of the CIPs to distribution customers include:

- **Reliability**: the solution proposed to safely and reliably interconnect group study DER, in many cases coincidently, addresses existing or projected system needs. The proposed upgrades, if approved, expedite addressing these reliability concerns. These include:
    - Electrical Power System (EPS) normal configuration thermal loading
    - EPS contingency configuration customer unserved
    - EPS asset conditions
- **Enabled electrification**: the proposed solution in some cases also provides thermal capacity beyond the planning horizon and supports some loading projects out to 2050.
- **Reserved Small Distributed Generation (DG)**: the proposed solutions also incorporate a reserved capacity on each study feeder for the small rooftops to interconnect without triggering major EPS upgrades, which typically is a direct benefit to distribution customers.

The high-level description of the common system modifications required to accommodate the interconnection of the DER included in the groups listed above are included in the Appendix. Note that these areas are in various stages of maturity and the modifications required across this sub-region have not been fully identified as of August 2023.

4.3.6 Grid Services (Demand Response, Smart Inverter Controls, Time-Varying Rates)

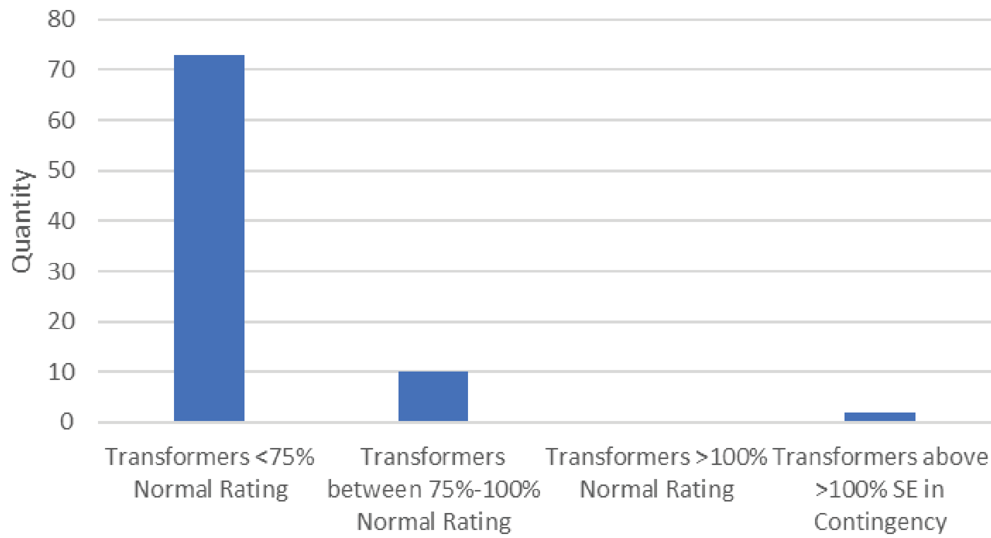
The Company currently offers several grid service participation opportunities to residential and commercial customers through its Demand Response and EV managed charging programs. Customers can earn incentives for curtailing load, pre-cooling with smart thermostats, charging their electric vehicles at optimal times, or shifting energy use with battery storage during peak load periods. As described in sections 6.3, 6.11, and 9.3 and 9.6 the Company is also on a path toward expanding grid services via AMI and time-varying rates, and leveraging DERMS technology investments to offer more dynamic, location-specific grid services as NWA solutions in the future.

In the Central sub-region over 4,800 customers currently participate in the Company's ConnectedSolutions DR program and help to reduce approximately 32 MW of load on the grid when the overall grid is at peak. This has helped to delay investments and maximize the utilization of the current network.

4.3.7 Capacity Deficiency

The graphs below summarize the forecasted asset loading across the Central sub-region in 2023. The 2023 loading profile shows that most assets are loaded below 75% of their normal rating.

Exhibit 4.16: Central sub-region 2023 Forecasted Transformer Loading Profile



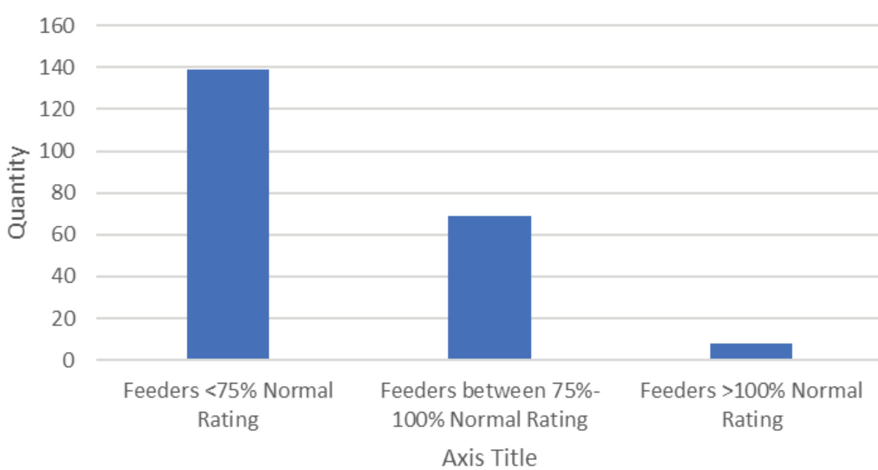
Substation transformer capacity deficiencies exist in the following areas:

Exhibit 4.17: Central sub-region 2023 Forecasted Transformer capacity deficiencies

Study Area	Substation	Capacity Deficiency
Millbury-Grafton	MILLBURY 4	Transformers > 100% Emergency Rating in Contingency
Ayer Clinton	AYER 201	Transformers > 100% Emergency Rating in Contingency

There are operational protocols that go into effect to manage the risk of overloading of transformers upon a contingency event (e.g., the loss of a neighboring transformer).

Exhibit 4.18: Central sub-region 2023 Forecasted Feeder Loading Profile



Eight feeders in the Central sub-region have an identified existing capacity deficiency. This deficiency is being monitored as anticipated growth and spot loads come into service, and operational mitigations will manage the overload as appropriate. A permanent switching plan was put in place for one projected feeder overload in East Webster.

This Central sub-region has 16 substations that are supplied by 69kV transmission lines. The 69kV transmission lines will be a limiting factor for additional substation capacity in this area. Plans to increase substation capacity must therefore anticipate a future transmission voltage conversion from 69 kV to 115 kV.

The city of Worcester is primarily supplied by the 4.16kV system. The system consists of 80 circuits and 26 substation transformers. A 1902 Worcester Bylaw prohibited overhead wires within a 2-mile radius of Worcester City Hall. The Company's solution to this was to install overhead facilities in customers' backyards with underground cable and switches in the public way. There are approximately 1,100 backyards. Due to protection concerns, the maximum overhead service transformer size in backyards is 50 kVA. To support the electrification of vehicles and heat in these communities, and with the projected 2050 winter load, maintaining the backyard configuration in this area would require an additional 1,500 backyard transformers, or approximately doubling the existing population impacted. The backyard construction also presents storm restoration challenges due to private property access. The 4kV system is beginning to have normal loading issues and will not be able to support the projected load growth in the area. In other words, the existing backyard construction cannot efficiently or reliably support electrification in this region through 2050.

The city of Worcester is also supplied by a non-effectively grounded "High-Tension"[14] system that operates at 13.8kV. The non-effectively grounded system presents challenges for DER interconnections, including technical requirements that impose high cost and/or real estate requirements on these projects that often in the Company's experience render them inviable.

4.3.8 Aging Infrastructure

This section is only illustrative for completeness of the system, and as such, relevant aging infrastructure investments are defined to be part of "core operations" and additional funding is not proposed in this plan. The investments proposed in this Future Grid Plan are driven by load growth and the need to increase system capacity.

As energy infrastructure ages, and often consequently, its condition worsens, the risk of equipment failure increases and the reliability of operation decreases. The age of infrastructure is an important consideration when assessing the condition of assets and in efforts to meet the future customer demands. However, asset replacement is driven primarily by asset condition rather than time of life. The Company's approach to maintenance has moved from a time-based approach to risk and condition based as a result of digitizing information and having real-time data. Substations and distribution lines are surveyed regularly to assess asset health and to make recommendations for replacement. Assets are rated based on a range of criteria to assess their health, which drives asset condition

[14] This system was called "High-Tension" at the time of its installation in the early 1900s to refer to the fact that these circuits operated at a higher voltage or "tension" and functioned as sub-transmission supply to other substations, while most distribution facilities were operated at 2.4 kV. The Company has maintained this legacy naming convention for these unique non-effectively grounded circuits, even though we no longer think of 13.8 kV as a "high" voltage and these lines are now also used to supply customers directly.

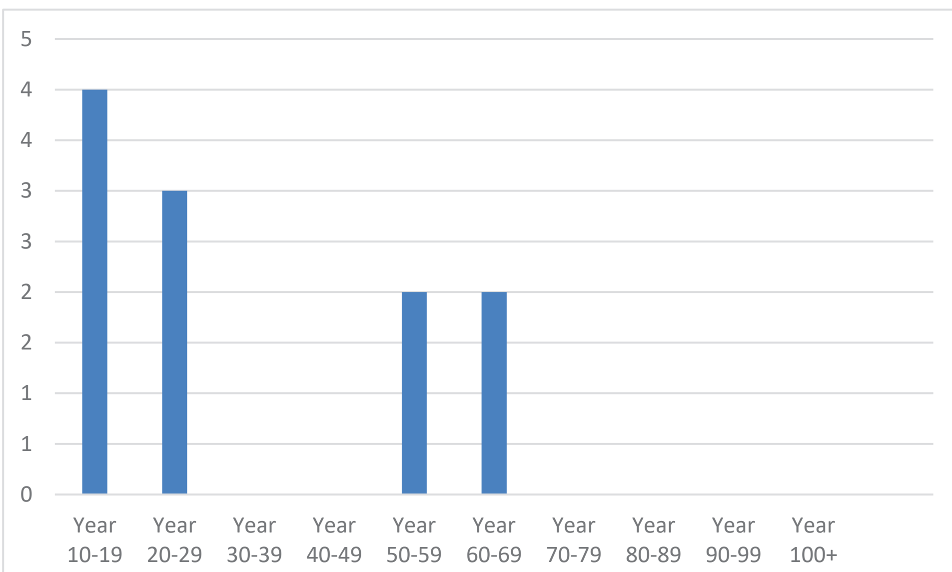
replacement projects. Standard maintenance and regular testing (e.g., inspecting and replacing subcomponents of a circuit breaker) can greatly enhance reliability and extend the life of specific assets. Often, assets exceed their life expectancy if their condition and risk profile allow it, enabling the Company to maximize the value of assets while maintaining network reliability.

Additionally, as the Company moves towards modernizing and standardizing the grid and/or substations, existing equipment may need to be modified or replaced in order to digitize current methods. It is important the Company remains diligent in improving its infrastructure with new technologies and remaining environmentally focused (e.g., changing substation support structure design from aluminum to steel due to efficiency and decarbonization). This type of modernization work will fit into core and Future Grid Plan work, depending on the project driver (asset condition or system capacity/load growth, respectively).

The following Exhibits illustrate the age of select key components of energy infrastructure today. Many of these assets are approaching the end of life and will require condition-driven replacements in the future.

Exhibit 4.19 below shows the metalclad age profile in the Central sub-region. Metalclad or metalclad switchgear refers to a key substation component in certain types of substations. The metalclad switchgear is a metal building that houses circuit breakers, protective relays and controls, and bus, typically on the low-voltage side of the substation transformer[15]. Since all the circuit breakers, protection and control, communications, metering, and auxiliary equipment are enclosed within the switchgear enclosure, it provides one of the most compact and economical approaches to building a multiple feeder distribution substation. This provides a controlled environment for the batteries and the protective relays, metering, and monitoring devices. Maintenance of much of the substation equipment can be performed without hindrance from weather conditions. Key age-related concerns for metalclad switchgear are related to the degradation of the metal enclosure, which may allow water and animal intrusions that lead to equipment damage and/or outages to all or some of the feeders supplied by the metalclad.

Exhibit 4.19: Central sub-region Metalclad Age Profile



[15] IEEE Std. C37.20.2-2015 Standard for Metal-Clad and Substation-Type Cubicle Switchgear and NEMA standards SG-5 and SG-6 define the necessary technical characteristics for metalclad switchgear.

Exhibit 4.20 below shows the substation transformer age profile in the Central sub-region.

Exhibit 4.20: Central sub-region Substation Transformer Age Profile

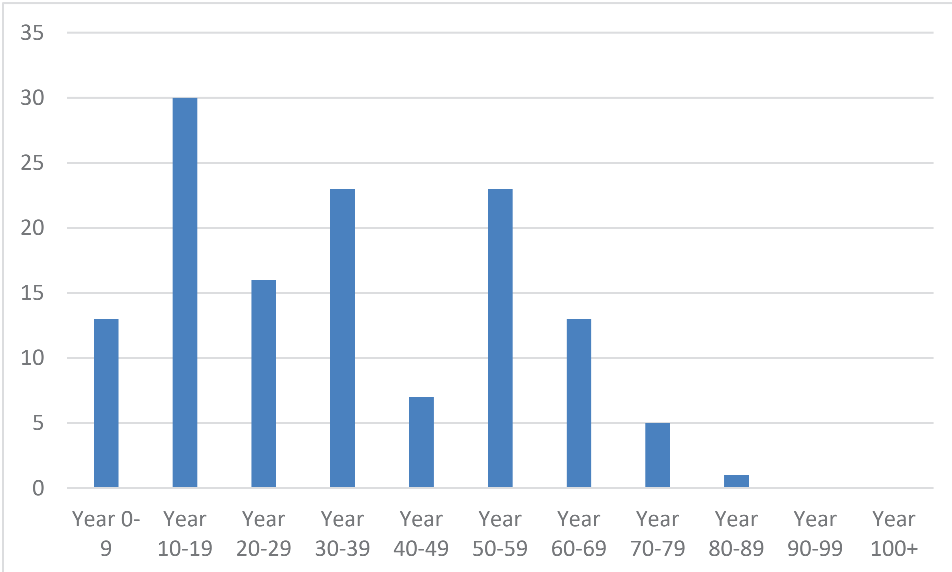


Exhibit 4.21 below shows the distribution pole age profile in the Central sub-region.

Exhibit 4.21: Central sub-region Distribution Pole Age Profile

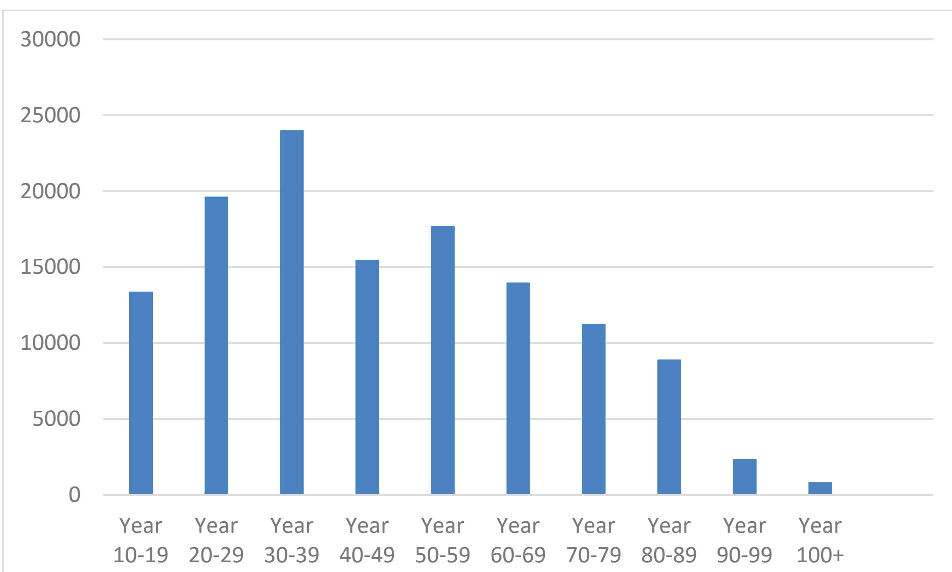
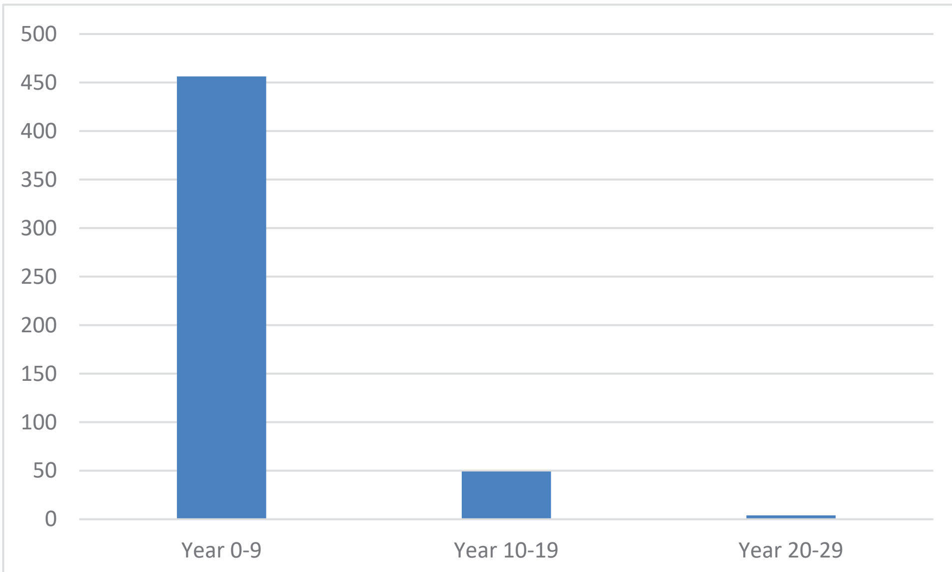


Exhibit 4.22 below shows the recloser age profile in the Central sub-region. Reclosers are pole-mounted distribution line equipment which respond to faults by opening to isolate the sections of circuits that are damaged. They can "reclose," attempting to restore power following the fault several times before finally locking out if the damage is permanent and must be repaired by line crews before the line can be safely re-energized. This reclosing behavior means that for temporary faults, (e.g., a branch that falls across the wires and then falls to the ground), customers only experience a momentary outage. Reclosers can also work in automated schemes such as FLISR, to reconnect and restore portions of customers in a more sophisticated and coordinated manner than the simple isolation of faults.

Exhibit 4.22: Central sub-region Recloser Age Profile



4.3.9 Reliability and Resilience

This section will describe how the Company reports reliability and what the current reliability metrics are for this given sub-region. For additional information on reliability, resiliency, and company performance, the Company's annual report is here (Department Docket No. 12-120-D). This section is only illustrative for completeness of the system, and as such, relevant reliability investments are defined to be part of "core operations" and additional funding is not proposed in this Future Grid Plan. The investments proposed in this Future Grid Plan are driven by load growth and the need to increase system capacity.

As described in detail in section 10, reliability issues are largely due to abnormal and/or hazardous conditions, such as flooding, high winds, and wildfire, and are not directly driven by increased electrification. However, the Company recognizes electrification's role in increasing dependence on a reliable and resilient distribution system. While none of the investments in this Future Grid Plan are directly prompted by reliability considerations, there are synergies from the Future Grid Plan that also improve customer reliability by coincidence.

In the Commonwealth, the Company has historically adopted System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI), all defined below, as the standard metrics for quantifying the quality of service experienced by customers during "blue-sky days" (i.e., excluding major storms). The interruptions included in the formulas and results shown below are interruptions lasting longer than 1 minute, referred to as "sustained outages." Further exclusions of events not reported include major storms, loss of supply events during blue-sky days, planned outages during blue-sky days, and customer-equipment outages during blue-sky days.

SAIDI means the total duration of customer interruptions in minutes divided by the total number of customers served by the distribution Company, expressed in minutes per year. SAIDI characterizes the average length of time that customers are without electric service during the reporting period. It is commonly measured in minutes or hours of interruption and is mathematically expressed as16:

$$SAIDI = \frac{\sum Customer\ Minutes\ of\ Interruption\ (CMI)}{Total\ Number\ of\ Customers\ Served}$$

SAIFI means the total number of customer interruptions divided by the total number of customers served by the distribution Company, expressed in number of interruptions per customer per year. SAIFI characterizes the average number of sustained electric service interruptions for each customer during the reporting period. It is mathematically expressed as:

$$SAIFI = \frac{\sum Total\ Number\ of\ Customers\ Interrupted\ (CI)}{Total\ Number\ of\ Customers\ Served}$$

CAIDI means the total minutes of customer interruptions for a circuit divided by the total number of customers connected to the circuit, expressed in minutes per year. If the total number of customers connected to the circuit differs from interruption to interruption, then the average number of customers served by that circuit shall be used. CAIDI characterizes the average length of time customers connected to a circuit are without electric service during the reporting period. It is mathematically expressed as:

$$CAIDI = \frac{\sum Customer\ Minutes\ of\ Interruption\ (CMI)}{Total\ Number\ of\ Customers\ Served} = \frac{CMI}{CI} = \frac{SAIDI}{SAIFI}$$

These metrics are standardized for reliability tracking across the utility sector; baselines and comparisons with other utilities can be enabled not just on performance but also in relation to technology deployment and other reliability improvement mechanisms.

As mentioned above, the metrics are called “blue-sky” reliability metrics, where major storm events are typically excluded. This allows for the drivers of day-to-day reliability and the actual 24/7 customer experience to be discernible. The drivers of reliability, the day-to-day customer experience, have the potential to be inherently different from the drivers of major storm performance, is referred to as resilience events. Therefore, it is necessary to separate major event experience from day-to-day customer experience.

However, SAIDI and SAIFI can be similarly used as a basis to quantify system performance during major events for system resiliency purposes, by creating a parallel SAIDI/SAIFI evaluation that includes all sustained outages (i.e., outages with duration longer than 1 minute) at all times, during major events in the calculation. Those are referred to as All-In SAIDI and All-In SAIFI. Since reliability is a subset of resiliency, the continuum of the customer experience from blue-sky to black-sky is best represented by using parallel, comparably devised metrics. This is also the best approach to understand and account for the impact of resiliency measures on reliability, and vice versa.

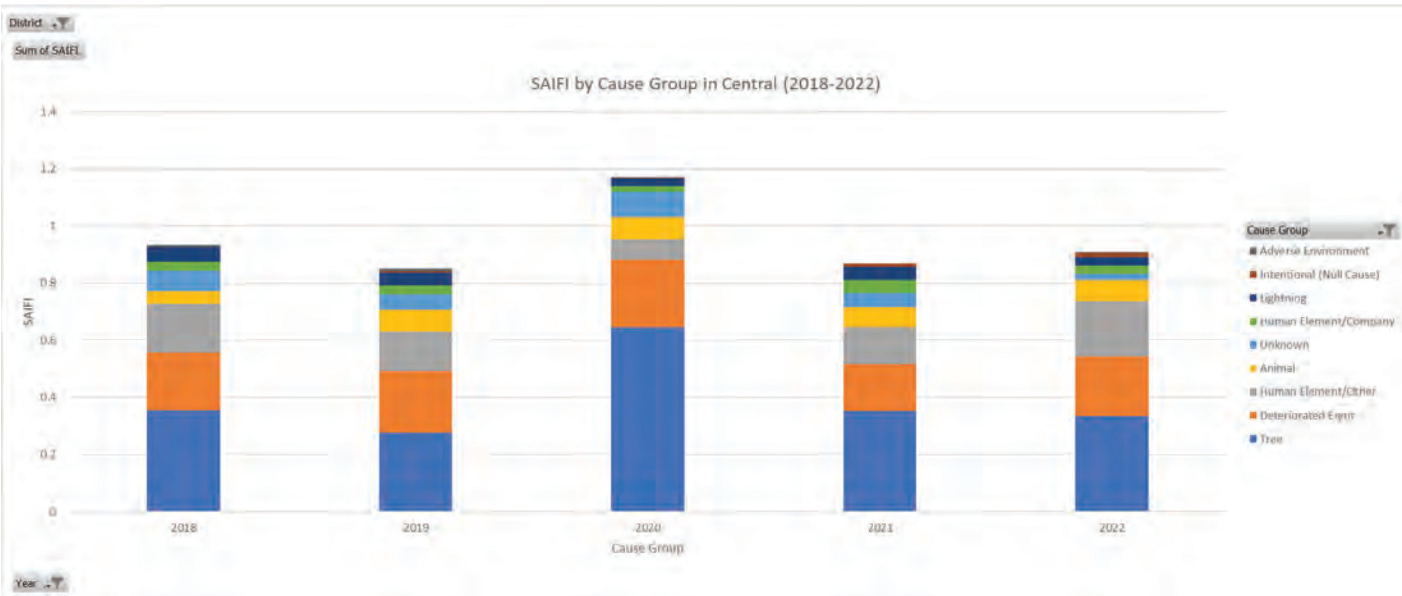
[16] [1] IEEE 1366-2012

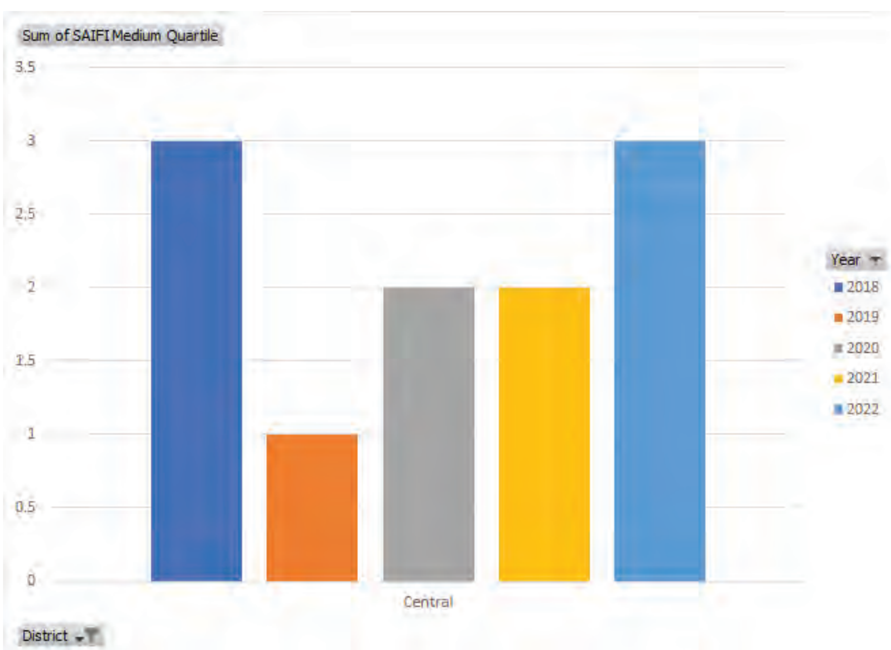
Reliability performance

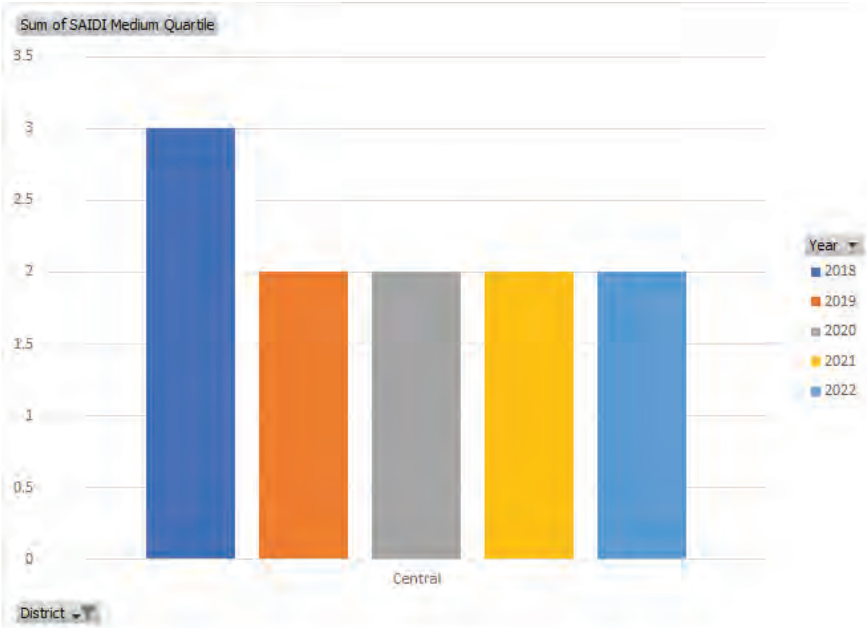
The exhibits below show the reliability performance of the Central sub-region in terms of duration (SAIDI) and frequency (SAIFI) of outages. The data in these Exhibits excludes major events, consistent with the Company's regulatory reporting criteria and call out leading causes of blue-sky outages for the region.

Tree-related events caused the majority of outages across this sub-region, in terms of duration and frequency.

Exhibit 4.23: Central sub-region Leading Causes of Blue-Sky Outages and SAIDI and SAIFI Reliability Performance







The sub-region-specific indices above are calculated using outage and electric customer counts specific to the sub-region. This can facilitate comparison between sub-regions. For example, the average customer in sub-region A. experienced more/fewer outage minutes in a given year than the average customer in sub-region B. but these sub-region values cannot be added together to arrive at the total system-level indices for that year, and so cannot be used to understand how much of a given year's system-level reliability performance was attributable to a given sub-region.

The IEEE Guide for Electric Power Distribution Reliability Indices, Standard 1366, was developed to facilitate uniformity in distribution service reliability indices and to aid in consistent reporting practices related to distribution systems, substations, circuits, and defined regions. While this methodology differs from the criteria applied to the Company's regulatory reliability reporting obligations, this approach was utilized to demonstrate the performance of the Company's distinct sub-regions as compared to similar size utilities responding to the survey (>100,000 - <1,000,000 customers). The benchmarking analysis showed that for three out of the last five years, Central has been in the first or second quartile for frequency of outages (SAIFI) and has been in the second quartile for the past four years for duration (SAIDI).

Resiliency performance

Outage impacts from major events are traditionally excluded from reliability reporting, as described above. Major events can contribute both significant durations and numbers of outages to SAIDI and SAIFI calculations, sometimes dwarfing the characterization of system performance for 364 days of the year based on the impacts from a single day. Nonetheless, analysis of system performance trends that include the impacts from these major events can provide valuable insights into how the system responds to these significant stressors, which are growing increasingly frequent due to climate change.

The Company calculated "all-in" SAIDI and SAIFI indices across its service territory to facilitate comparison of the resiliency and reliability challenges experienced in each sub-region relative to the others. This comparison highlights areas where emerging resiliency challenges have been experienced in the past five years. Note that due to the "low frequency high impact" nature of significant events that are excluded from traditional reliability reporting, the Company continues to monitor these trends and whether they are sustained over time.

For this analysis, the Company aggregated the outage events experienced at each of its substations over a five-year period 2018-2022 and calculated the resulting substation-level SAIDI and SAIFI. This calculation included all events, including major storms. The resulting SAIDI and SAIFI values for each substation were then ranked for all the Company's service territory. Tier designations were made to indicate each substation's performance relative to all other Company substations for this time period. Note: these tiers illustrate internal benchmarking for relative comparison between the Company's substations across its service territory and differ from the IEEE metrics and benchmarking analysis described in the preceding section. Substations may have no reliability data for several reasons, including no recorded events over the time period or if they do not directly serve load to customers.

The following maps illustrate the substation resiliency of this sub-region overlaid with Environmental Justice Areas, as defined by the Commonwealth. The exhibits below show the Company's distribution substation locations within the given sub-region overlaid with Environmental Justice Areas. Each distribution substation is color-coded indicating its five-year historical SAIDI or SAIFI performance relative to the Company's entire population of substations. A greater density of distribution substations, typically results in shorter distribution feeders with less outage exposure and increased numbers of feeder ties, resulting in better overall reliability. As can be seen in each of these Exhibits, substations in the Environmental Justice Areas fall within the top first and second quartile of SAIDI and SAIFI performance relative to the entire population of the Company's distribution substations.

Exhibit 4.24: Central sub-region Resiliency in EJCs as shown as SAIDI Substation Performance

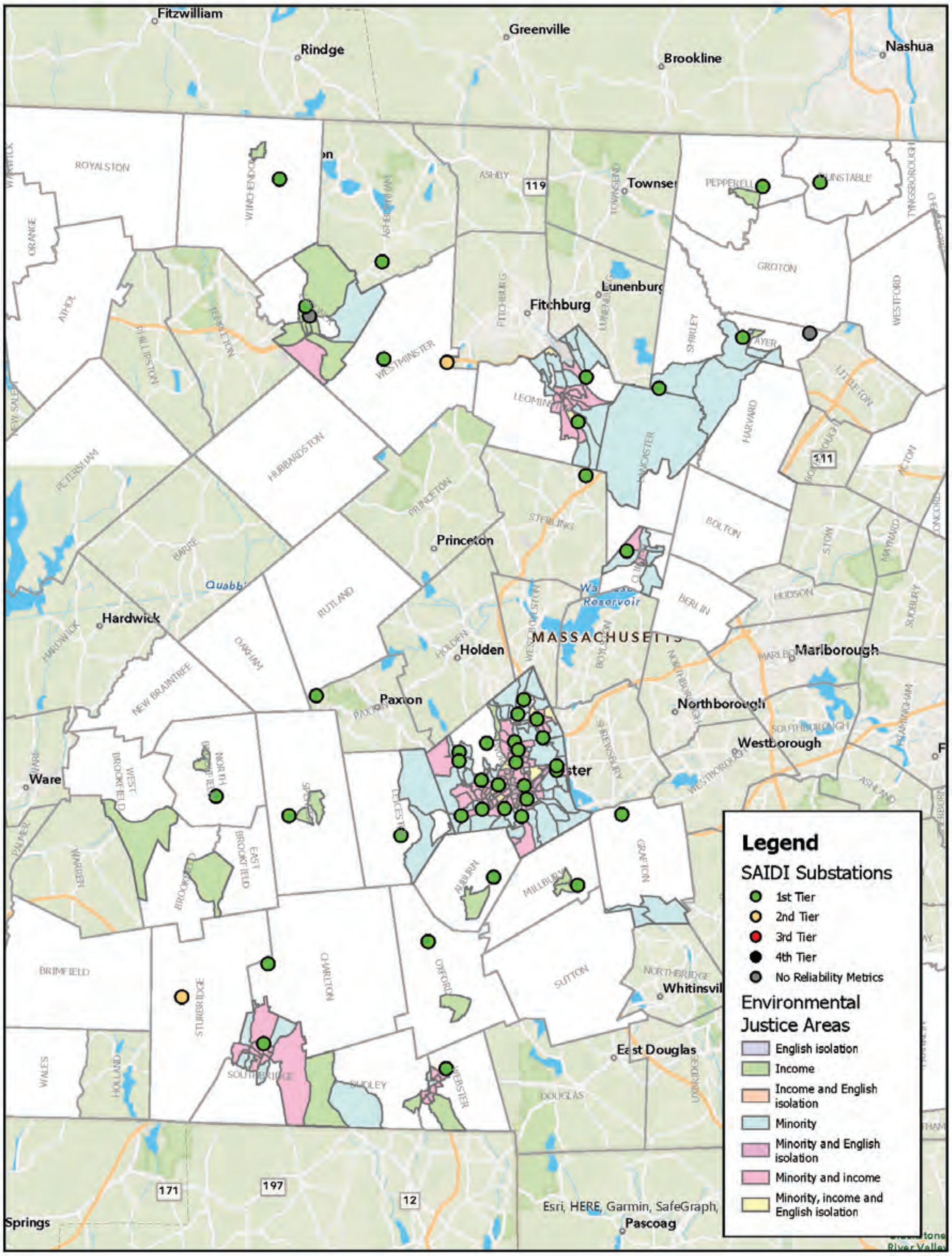
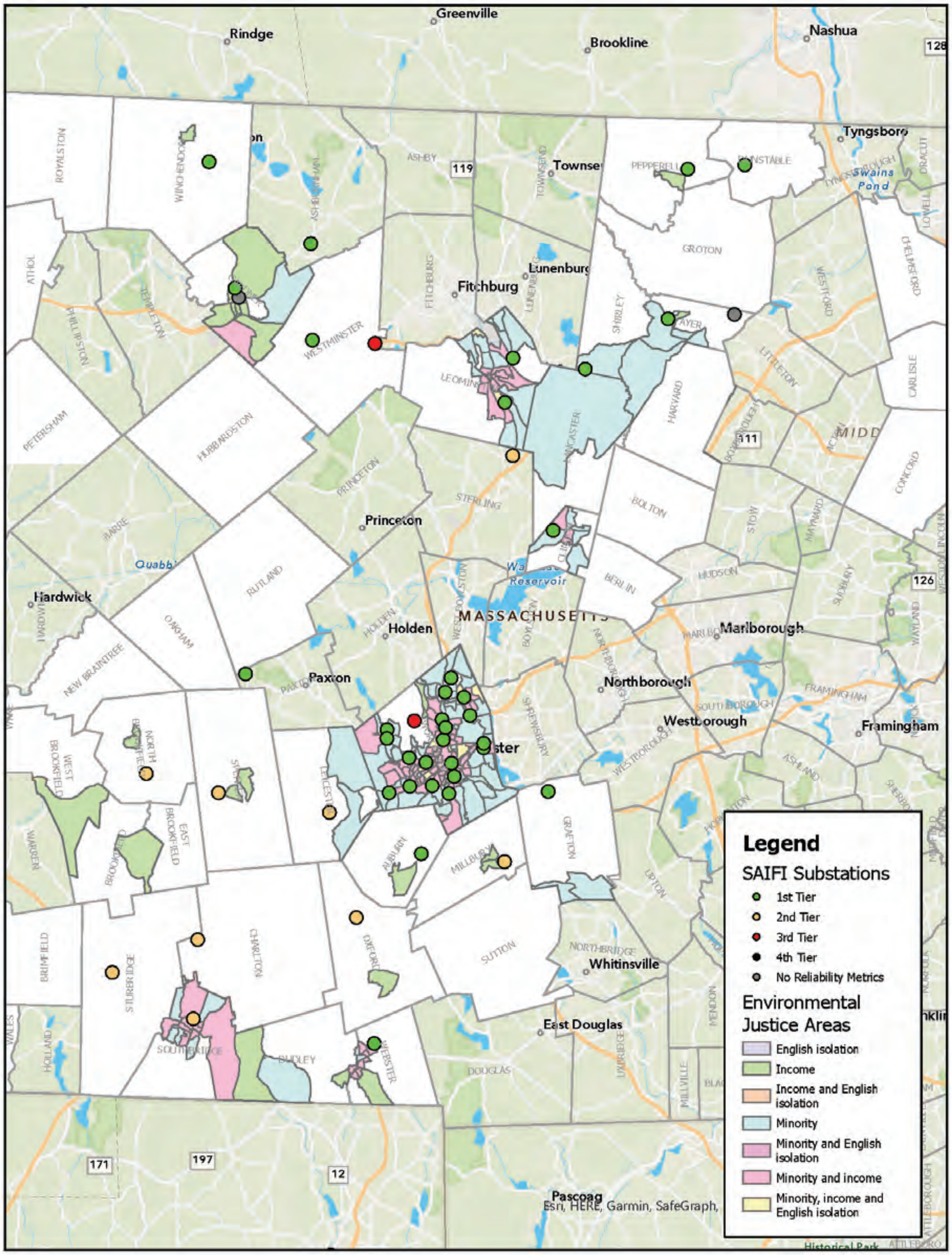


Exhibit 4.25: Central sub-region Resiliency in EJCs as shown as SAIFI Substation Performance



When looking at the 5-year performance, 2020 was a particularly bad year as the company experienced 18 storm events that were not classified as major events. The impact of each event added together reflects the bad reliability performance at the system level. Also worth noting was that 2018 and 2021 were bad years of performance for the eastern part of the Company's Commonwealth service territory given three back-to-back storms occurring in early 2018 and a Nor'easter occurring in October 2021. As a result, substations in the fourth quartile of SAIDI/SAIFI performance can be seen in South Shore, Southeast and Merrimack Valley region maps.

4.3.10 Siting and Permitting

Energy infrastructure siting and permitting processes are generally consistent across the Commonwealth; therefore, siting and permitting challenges do not vary significantly by region. When projects require considerable underground transmission work, the Energy Facilities Siting Board (EFSB) review process is triggered to ensure the work is in compliance with State requirements. This EFSB review process is intended to take twelve months (see G.L. c. 164, Section 69J); however, the review timeline for recently submitted transmission line projects is trending toward 30 to 36 months.

Environmentally, the largest differences are at a municipal level rather than regionally. At the project-level, Conservation Commission impacts uniformly across the State but there is a high degree of variability town to town and year to year, which makes it challenging to generalize regionally. For example, in the central region, the Company has energy infrastructure in urban and rural locations. Each of these settings present different siting and environmental considerations.

4.4 Merrimack Valley Sub-Region

The Merrimack Valley in brief:

Nature of the Area: The Merrimack Valley sub-region is predominantly suburban, with regional urban centers in Lowell and Lawrence. Smaller urban/town centers can be found in Amesbury, Haverhill, Methuen, and Newburyport.

The Company's customers' energy needs, economic circumstances and demographics in the Merrimack Valley sub-region vary greatly, which is why targeted, and culturally competent community engagement is at the core of the Company's plan to help the State achieve its goals.

Exhibit 4.26 Merrimack Valley sub-region customers by the numbers

Total Customers (accounts)	% Residential	% Business, Commercial, Municipal, or University	Benefits of EE	Heat Pump Adoption (end of 2022)	Total NG Charging Ports Installed
263,871	88%	12%	1,331,336 MWh	1,225	379 Ports

Exhibit 4.27: Merrimack Valley sub-region network by the numbers

Number of Substations	Number of Feeders	Total Length of Feeders	Total peak Load Served	Square miles of Sub-Region
58	297	3,400 miles	1,212 MW	386

Context of the region

The Merrimack Valley sub-region includes some of the most consistently dense communities in the Commonwealth. This sub-region has average levels of DER penetration relative to all other sub-regions due to the somewhat limited amount of open space coupled with more robust distribution infrastructure as compared to the western area of the Commonwealth. Due to the large population and growing suburban areas, an approximate 6.9% load growth is expected in the central region in the next 5 years. Additional details can be found in Section 5.

Below are some key characteristics of the Merrimack Valley sub-region which will drive future investment needs.

Exhibit 4.28 Merrimack Valley Sub-Region Key Characteristics that will Drive Future Investment Needs

Network Characteristic	Consequence
The majority of the distribution circuits in the region are 15 kV class circuits, which operate at voltages of 13.2 kV or 13.8 kV. There are 77 circuits that operate at 4.16 kV which primarily supply Andover, Lawrence, and Lowell, and are supplied from substations that step down the voltage of 13 kV or 23 kV to supply customers. Lower voltages such as 4.16 kV were used more commonly in the past when loads were lower.	Areas served by these lower voltages will largely need to be converted to a higher voltage such as 13.2 kV or 13.8 kV in order to meet the significant load growth that is projected across the State. Voltage conversions can be costly and complex projects, requiring widescale replacement or upgrade of significant amounts of both distribution line and substation facilities.
An extensive 23 kV class subtransmission system in the area acts both as supplies to substations and to serve mostly larger load customers.	Subtransmission circuits have less capacity than transmission circuits; therefore, load growth on subtransmission-supplied substations can sometimes be limited by the subtransmission feeder supplying it. As a result, the Company will need to invest in both the substation and extend transmission facilities into these areas to meet the projected load growth.

4.4.1 Maps

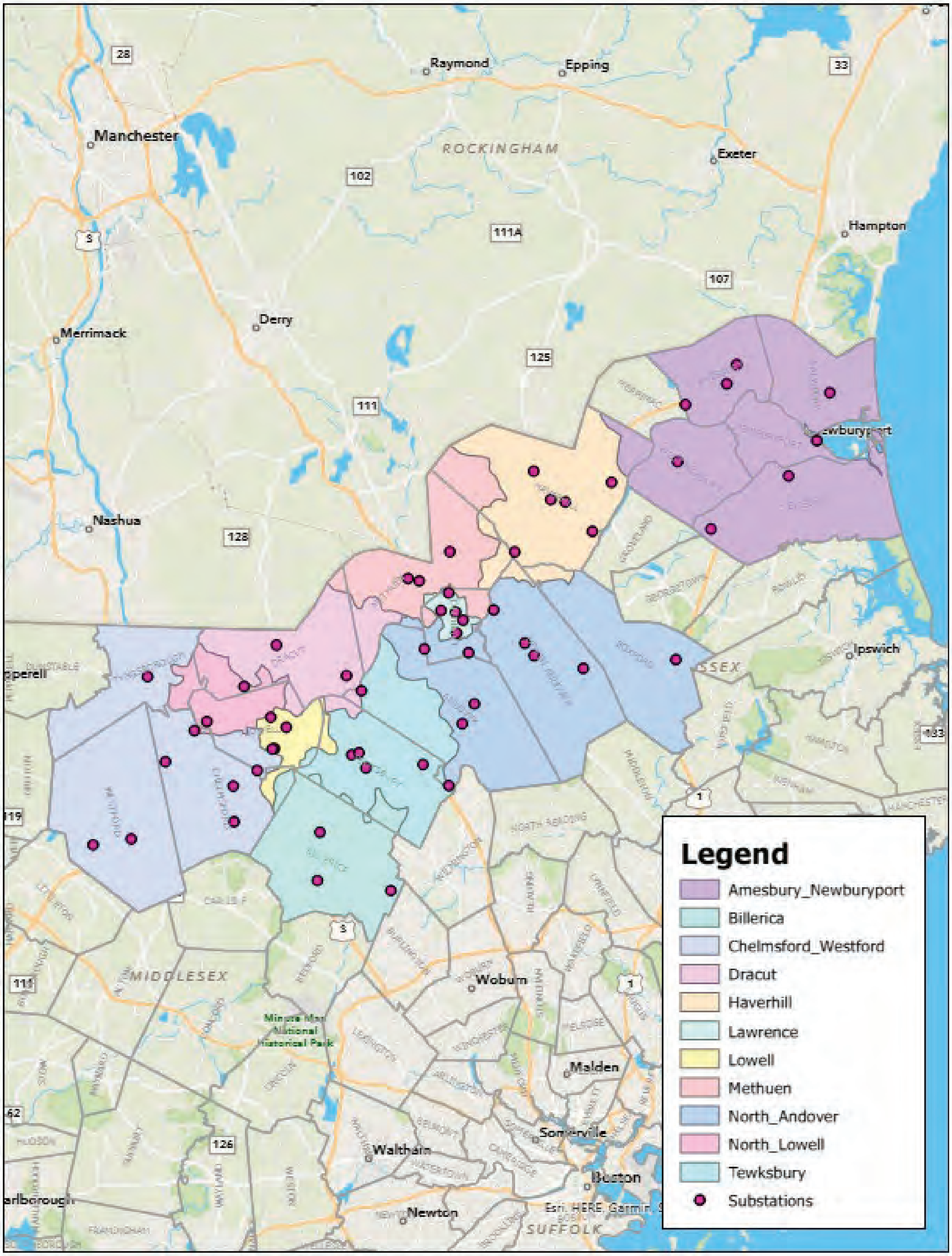
The Company's Merrimack Valley sub-region consists of 18 towns and cities and comprises the study areas below:

Exhibit 4.29: Merrimack Valley Sub-Region Study Areas and Towns

	Study Area	Town
1	Amesbury/Newburyport	Amesbury, Haverhill, Newbury, Newburyport, Salisbury, West Newbury
2	Billerica	Billerica, Chelmsford, Tewksbury
3	Chelmsford/Westford	Chelmsford, Lowell, Tyngsborough, Westford
4	Dracut	Andover, Dracut, Lowell, Methuen, Tewksbury
5	Haverhill	Boxford, Haverhill, Methuen, North Andover
6	Lawrence	Lawrence, Methuen
7	Lowell	Chelmsford, Lowell, Tewksbury
8	Methuen	Dracut, Haverhill, Lawrence, Methuen
9	North Lowell	Dracut, Lowell, Tyngsborough
10	Tewksbury	Andover, Billerica, Lowell, Tewksbury

Exhibit 4.30 below shows the substation locations within the Merrimack Valley sub-region's study areas, indicated with a red dot. Not all study areas cleanly follow town lines because they are defined electrically instead of geographically. Many of the locations of substations in the Merrimack Valley sub-region were driven by the need to provide electricity to the mills that existed in the early and mid-20th century, which were located along the rivers. Recent revitalization and economic development have resulted in conversion of many of these mill properties to residential and commercial businesses.

Exhibit 4.30: Merrimack Valley sub-region Substation Locations and Study Areas



4.4.2 Customer Demographics

Exhibit 4.31: Merrimack Valley sub-region customer demographics summary

Number of Customers				Residential Population Growth	Benefits of EE	Existing Connected Rooftop DER (< 25kW)
Total	Residential – Total	Residential – Low Income Rate Participants	Commercial	5-year Growth Projections		
263,871	231,279	32,181	32,592	1.7%	1,331,336 MWh	105 MW

The Company serves a total of 263,871 customers (defined by individual accounts, not the number of people served) – in the Merrimack Valley sub-region. Approximately 88% (231,279) of these customers are residential customers and the other 12% are comprised of commercial, municipal, or university customers.

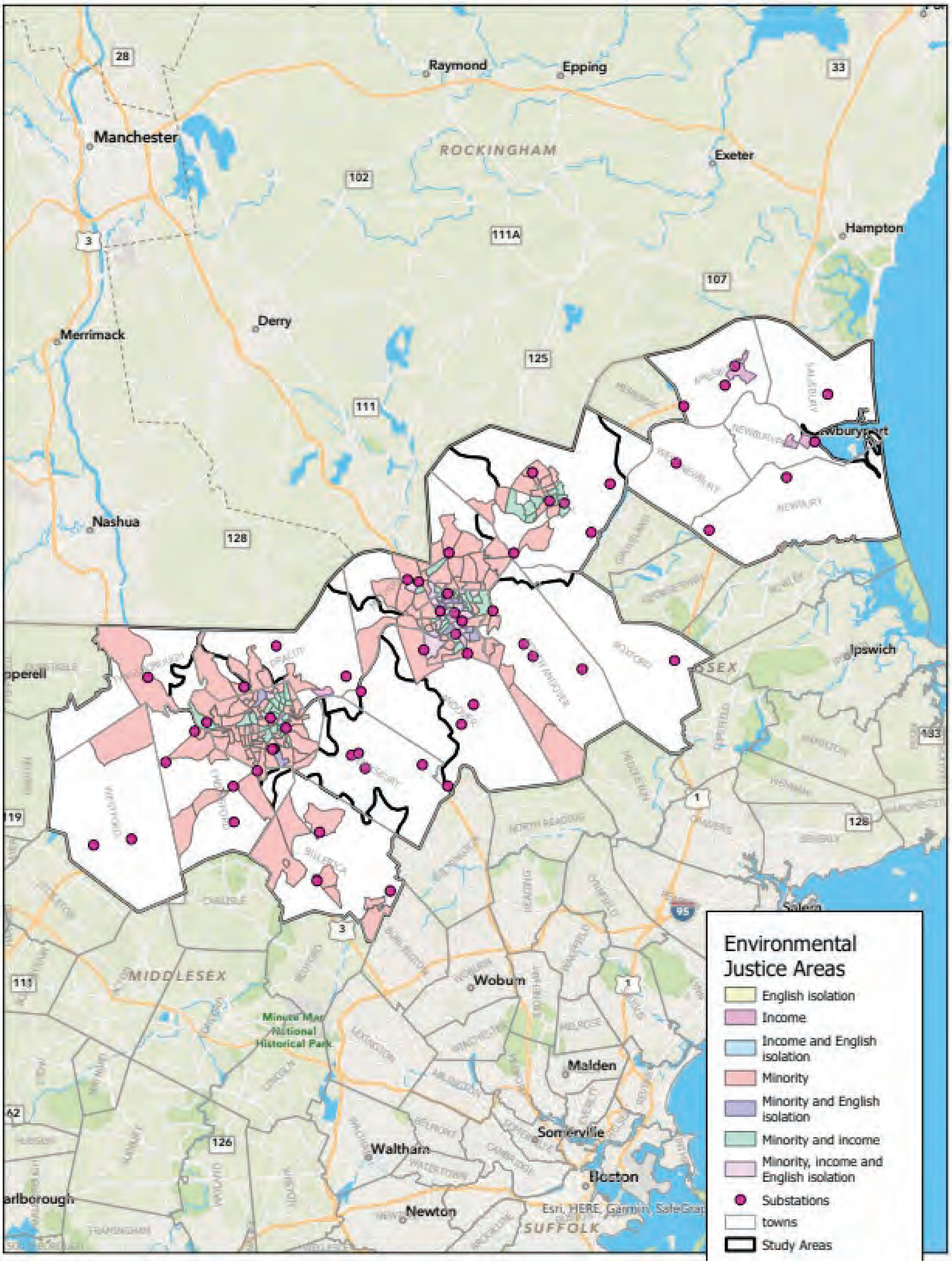
In addition to the Mass Save programs, which have benefited customers in the Merrimack Valley sub-region, 24 towns statewide have been identified for targeted outreach per the MA EEAC Equity Working Group plans. Under these outreach plans, the Company is specifically working to encourage more Energy Efficiency benefits in low-adoption zones. The towns/cities included in the Merrimack Valley sub-region are Billerica, Lawrence, Lowell, and Methuen.

The Company recognizes that a significant portion of the Company's customers live in EJCs, which are disbursed throughout the Company's service area. Historically, EJCs have borne the highest energy burdens and been disproportionately impacted by the fossil-based economy. As outlined earlier in Section 3.3, the Company is developing a formal Equity and Environmental Justice Policy and Engagement Framework, as well as complementary policy and framework focused on Indigenous Peoples, which the Company will seek feedback on from those communities prior to finalizing, please refer to the Appendix for those drafts.

Below please see Exhibit 4.32 which overlays the Commonwealth Environmental Justice Population map with the Company's current substations. [17]Exhibit 4.32 below highlights concentrations of substations in many load-dense areas – Lawrence, Lowell, town centers and other major economic areas with existing industry, or a history of industry. Load density and electric capacity needs are the key drivers to substation density and location. As the load increases, the need for more substations to serve these population centers and expanding rural areas will increase too. Many EEJCs have been identified as such by the Commonwealth because they have been historically unduly burdened by infrastructure and related pollution. As discussed in Section 3, the Company is committed to being a trusted partner with all the Company's host communities, including those which contain EJCs, as new infrastructure needs to be built throughout the Commonwealth to reach decarbonization and electrification goals. Additional infrastructure that has yet to be built per recommendations in this Future Grid Plan can be found in Section 6.

[17] Multiple substations in close proximity with one another may appear to be overlapping or as one dot on this map

Exhibit 4.32: Merrimack Valley sub-region Substation Locations in Relation to the Commonwealth's EJCs



4.4.3 Economic Development

The development of the Company's Grid Future Plan was informed, in part, by the varying levels of readiness within each sub-region. Within the Company's study areas, 14 communities have completed decarbonization plans and 139 are designated as "green communities" under M.G.L. c. 25A §10. In partnership with the Company, the following municipalities have completed a Strategic Energy Management Plan (SEMP): Athol, Beverly, Everett, Lowell, Melrose, Newburyport, and Salem. The Company anticipates one new SEMP to be signed before the end of the year, with an additional five SEMPs in the development queue.

In the Merrimack Valley, two communities (Westford and Newburyport) have completed a decarbonization plan, two communities, in partnership with the Company, have completed a SEMP, and all 13 communities are designated as green communities. The region's focus over the next five years is to increase the supply of affordable housing, promote workforce development, enhance connectivity to public transportation, and develop available commercial and industrial space. Each of these initiatives are supported by programs such as MassDevelopment's Transformative Development Initiative (TDI). This initiative targets Gateway Cities to accelerate economic growth at the neighborhood level, while CEDS envisions the region as a climate-resilient community and economic activity hub through vibrant downtowns, main streets, commercial districts, and outdoor spaces. These and other programs are supported by local leaders, developers, and regional organizations such as The Lowell Plan, Lowell Chamber of Commerce, UMASS-Lowell, Middlesex 3 Coalition, Merrimack Valley Chamber of Commerce, regional banks and numerous social service agencies.

4.4.4 Electrification Growth

Heat electrification – Merrimack Valley has moderate heat pump adoption with about 850 units installed by the end of 2022, of which nearly 60% are hybrid.

Transport electrification – There has been consistent growth in LDEV sales in Merrimack Valley to date with a moderate amount of about 5,000 vehicles purchased cumulatively. The MHDEV count still remains extremely low. Since 2019, the Company has installed 379 EV charging ports via the phase I and phase II EV programs in the Merrimack Valley sub-region.

4.4.5 DER Adoption (Battery Storage and Solar Photovoltaic)

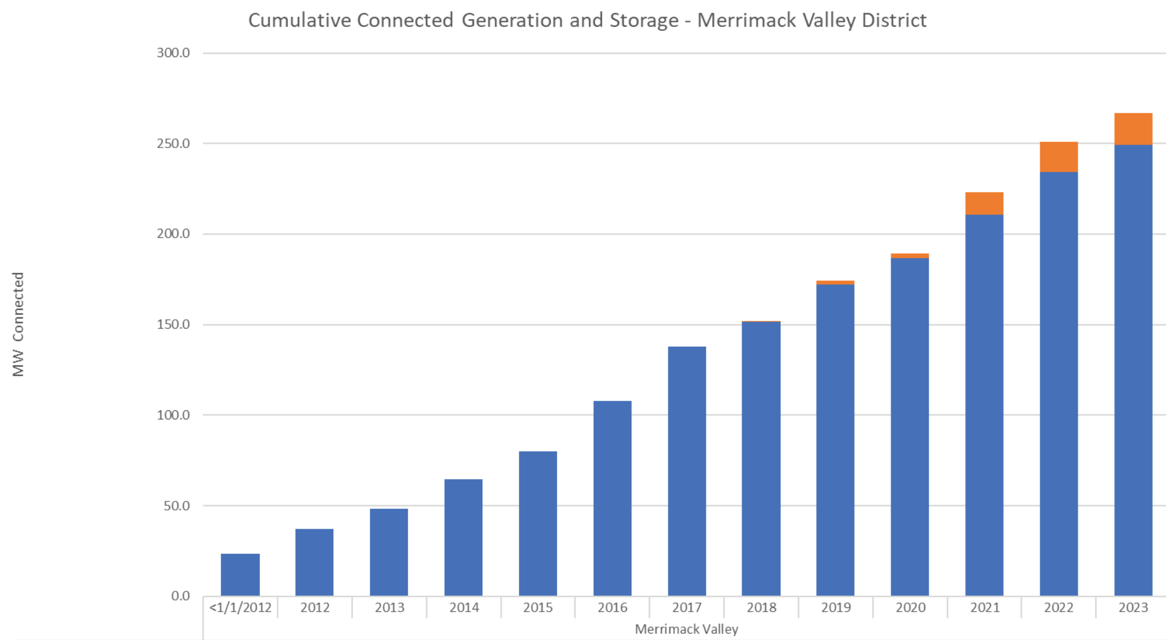
With a total of 265 MW of generation connected, the Merrimack Valley sub-region has relatively medium DER penetration. Connected DER is predominately solar, representing 90% of the installed DER capacity in the sub-region.

Exhibit 4.33: Merrimack Valley sub-region DER adoption summary

Sub-Region	Solar (MW)	Battery (MW)	Hydro (MW)	Wind (MW)	Miscellaneous[1] (MW)	Grand Total (MW)
Merrimack Valley - Connected DER	224.1	16.6	0.4	0.7	24.9	266.6

Note that in Exhibit 4.34 below, the 2023 value is reflective of cumulative interconnections as of July 2023.

Exhibit 4.34: Merrimack Valley sub-region Cumulative Connected Generation and Storage



	<1/1/2012	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Sum of Total Storage MW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	2.1	2.8	12.5	16.6	17.2
Sum of Total Generator MW	23.3	37.2	48.2	64.4	80.0	107.8	138.0	151.6	172.2	186.5	210.7	234.2	249.4

Exhibit 4.35 below contains the current DER interconnection queue in the Merrimack Valley sub-region as of July 2023. Recent application trends have demonstrated a shift from largely solar PV applications to mainly battery storage, with batteries representing 57% of the current queued DER capacity.

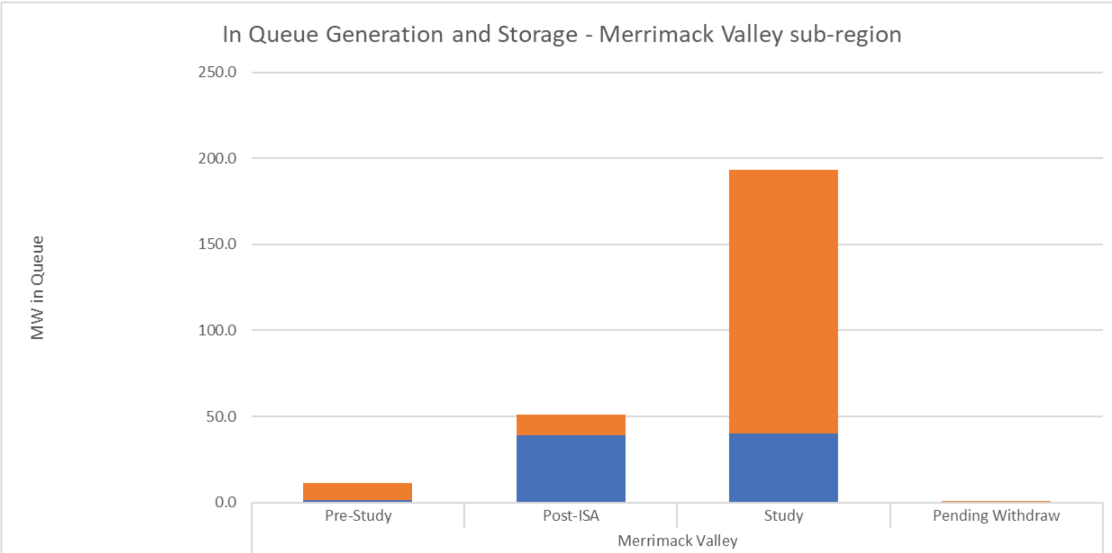
A large majority of the batteries are stand-alone, albeit some are co-located as PV paired with storage. Unlike other forms of DER, which operate solely in a discharge or export capacity, contributing power to the grid, standalone batteries also must charge from the grid. While solar and other forms of DER, excluding batteries, only require there to be sufficient grid hosting capacity for their interconnection, batteries require both hosting and load-serving capacity at the location of their interconnection. Therefore, batteries are subject to capacity deficiency (i.e., charge) considerations such as those highlighted in Section 4.4.7 as well as any hosting capacity (i.e., discharge) constraints that may be present.

This significantly increases the complexity of planning and operating the network.

Exhibit 4.35: Merrimack Valley sub-region pending DER summary in queue

Sub-Region	Solar (MW)	Battery (MW)	Hydro (MW)	Wind (MW)	Miscellaneous[2] (MW)	Grand Total (MW)
Merrimack Valley - Pending DER	60.3	176.1	16.7	0.0	3.1	256.2

Exhibit 4.36: Merrimack Valley sub-region pending DER Generation and Storage in queue



	Pre-Study	Post-ISA	Study	Pending Withdraw
Sum of Total Storage MW	10.3	12.5	153.2	0.0
Sum of Total Generator MW	1.2	38.8	40.0	0.1

Between the 256.2MW of DER in the interconnection queue, and the 266.6MW already connected in the Merrimack Valley, the total for the area would be approximately 522.8MW if all in-queue projects move forward. While it is unlikely that all will connect, this would be a significant increase in the amount of interconnected DER in an already constrained area and would therefore require significant infrastructure expansion. Layering on the complexity of battery operation and solar variability, advanced grid management tools will be necessary in addition to the infrastructure build out to maintain the safety and reliability of the grid.

In the Merrimack Valley sub-region, the Company has analysis completed or in progress for group study for the interconnection of DER in the following study areas:

- Billerica
- Tewksbury
- Westford/Chelmsford

The proposed DER and system modifications required for the proposed groups have been included in the base case for the Future Grid Plan analysis; should the DER customers in these groups not proceed to interconnection, the investments described will need to be analyzed for the impacts of this attrition and adjusted appropriately. The Company is proposing to apply CIP cost allocation principles to these investments once they reach sufficient maturity.

The high-level benefits of the CIPs to distribution customers include:

- Reliability: the solution proposed to safely and reliably interconnect group study DER, in many cases coincidentally, addresses existing or projected system needs. The proposed upgrades, if approved, expedite addressing these reliability concerns. These include:
    - EPS normal configuration thermal loading
    - EPS contingency configuration customer unserved
    - EPS asset conditions

- Enabled electrification: the proposed solution in some cases also provides thermal capacity beyond the planning horizon and supports some loading projects out to 2050.
- Reserved Small DG: the proposed solutions also incorporate a reserved capacity on each study feeder for the small rooftops to interconnect without triggering major EPS upgrades, which typically is a direct benefit to distribution customers.

The high-level description of the common system modifications required to accommodate the interconnection of the DER included in the groups listed above are included in the Appendix. Note that these areas are in various stages of maturity and the modifications identified below are subject to change pending further analysis through the group study process. Cumulatively, to interconnect the 88 MW of DER proposed through the current group studies, the Company anticipates requiring system modifications that include the addition or upgrade of 1 substation transformer and approximately 10 miles of distribution line construction, at an estimated cost of $40M.

4.4.6 Grid Services (Demand Response, Smart inverter Controls, Time-varying Rates)

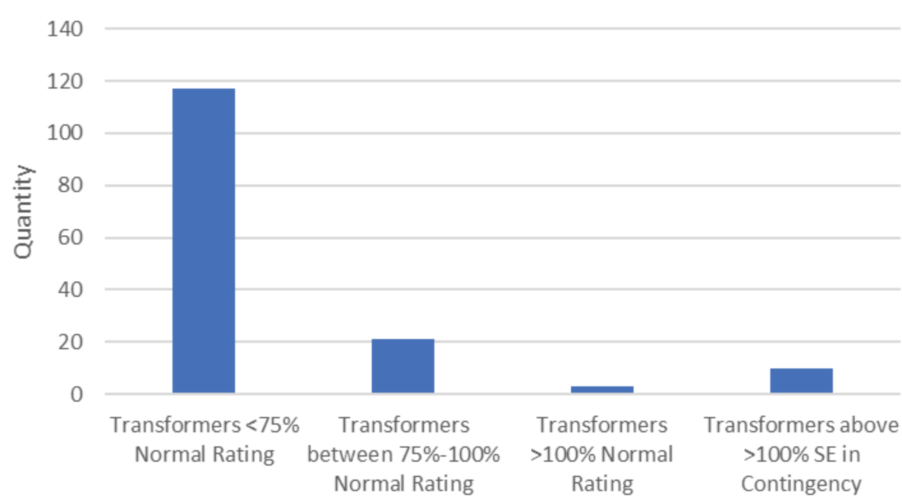
The Company currently offers several grid service participation opportunities to residential and commercial customers through its Demand Response and EV managed charging programs. Customers can earn incentives for curtailing load, pre-cooling with smart thermostats, charging their electric vehicles at optimal times, or shifting energy use with battery storage during peak load periods. As described in sections 6.3, 6.11, and 9.3 and 9.6 the Company is also on a path toward expanding grid services via AMI and time-varying rates, and leveraging DERMS technology investments to offer more dynamic, location-specific grid services as NWA solutions in the future.

In the Merrimack Valley region over 9,500 customers currently participate in the Company's ConnectedSolutions DR program and help to reduce approximately 23 MW of load on the grid when the overall grid is at peak.

4.4.7 Capacity Deficiency

Exhibit 4.37 below summarize the asset loading across the Merrimack Valley sub-region in 2023. The 2023 loading profile shows that most assets are loaded below 75% of their normal rating.

Exhibit 4.37: Merrimack Valley sub-region 2023 Forecasted Transformer Loading Profile



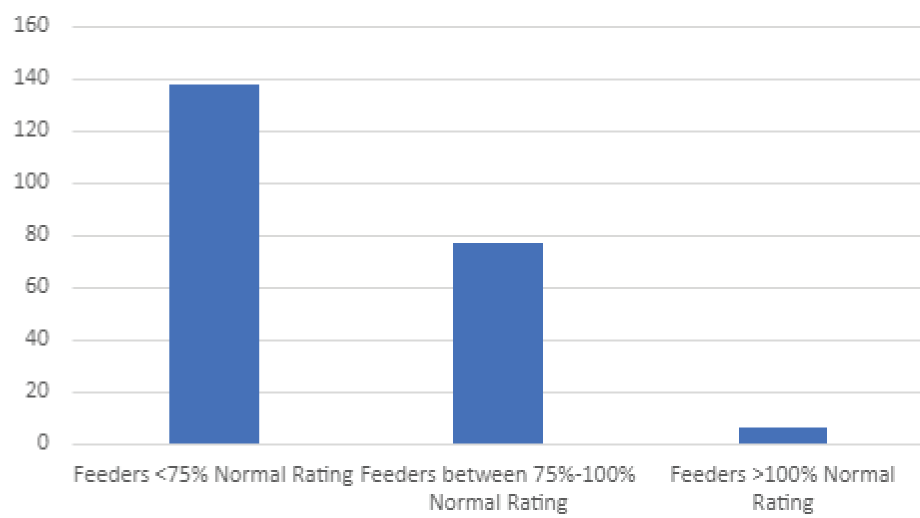
Substation transformer capacity deficiencies exist in the following areas:

Exhibit 4.38: Merrimack Valley sub-region 2023 Forecasted Transformer capacity deficiencies

Study Area	Substation	Capacity Deficiency
Lawrence	NORTH LAWRENCE 6	Transformers > 100% Emergency Rating in Contingency
North Lowell	BOULEVARD 77	Transformers > 100% Emergency Rating in Contingency
Tewksbury	EAST TEWKSBURY 59	Transformers > 100% Emergency Rating in Contingency
North Andover	WEST ANDOVER 8	Transformers > 100% Emergency Rating in Contingency
Haverhill	WARD HILL 43	Transformer > 100% Normal Rating
Amesbury Newburyport	WEST NEWBURY 47	Transformer > 100% Normal Rating
North Andover	SOUTH UNION ST 61	Transformer > 100% Normal Rating

There are operational protocols that go into effect to manage the risk of overloading of transformers upon a contingency event (e.g., the loss of a neighboring transformer).

Exhibit 4.39: Merrimack Valley sub-region 2023 Forecasted Feeder Loading Profile



Six feeders in the Merrimack Valley sub-region have an identified existing capacity deficiency. These deficiencies are being monitored as anticipated spot loads come into service, and operational mitigations will manage the overloads as appropriate.

The Merrimack River cuts through much of this area and adding or modifying any distribution infrastructure that needs to cross the river must be carefully considered during solution development, as such crossings can add significant complexity to projects.

The Merrimack Valley sub-region includes 30 substations which step the voltage down from 23 kV to a mixture of 13 kV and 4.16 kV, some of which have contingency loading and voltage performance concerns that limit the amount of load growth that can be supported by these substations.

Much of the Merrimack Valley sub-region shares a border with New Hampshire, and in some cases distribution facilities from one jurisdiction are supplied from the neighboring utility. In such cases, infrastructure investments in these areas must consider Liberty Utilities as a critical stakeholder.

4.4.8 Aging Infrastructure

This section is only illustrative for completeness of the system, and as such, relevant aging infrastructure investments are defined to be part of "core operations" and additional funding is not proposed in this plan. The investments proposed in this Future Grid Plan are driven by load growth and the need to increase system capacity.

As energy infrastructure ages, and often consequently, its condition worsens, the risk of equipment failure increases and the reliability of operation decreases. The age of infrastructure is an important consideration when assessing the condition of assets and in efforts to meet the future demands of the network. However, asset replacement is primarily driven by asset condition rather than time of life. The Company's approach to maintenance has moved from a time-based approach to risk and condition based as a result of digitizing information and having real-time data. Substations and distribution lines are surveyed regularly to assess asset health and to make recommendations for replacement.

Assets are rated based on a range of criteria to assess their health, which drives asset condition replacement projects. Standard maintenance and regular testing (e.g., inspecting and replacing subcomponents of a circuit breaker) can greatly enhance reliability and extend the life of specific assets. Often, assets exceed their life expectancy if their condition and risk profile allow it, enabling the Company to maximize the value of assets while maintaining network reliability.

Additionally, as the Company moves towards modernizing and standardizing the grid and/or substations, existing equipment may need to be modified or replaced in order to digitize current methods. It is important that that the Company remains diligent in improving the infrastructure with new technologies and remains environmentally focused. (e.g., changing substation support structure design from aluminum to steel due to efficiencies and decarbonization). This type of modernization work will fit into core and Future Grid Plan work, depending on the project driver (asset condition or system capacity/load growth, respectively).

Exhibit 4.40 below shows the metalclad age profile in the Merrimack Valley sub-region. Metalclads are further described in Section 4.3.8.

Exhibit 4.40: Merrimack Valley sub-region Metalclad Age Profile

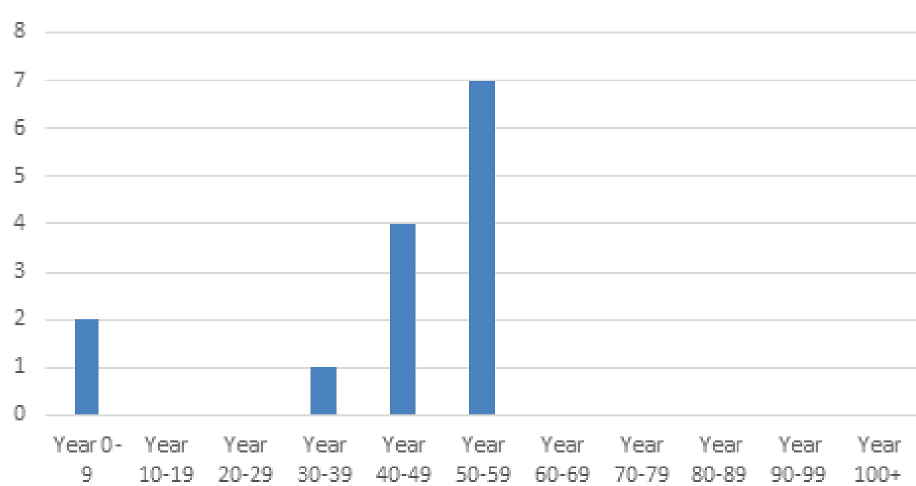


Exhibit 4.41 below shows the transformer age profile in the Merrimack Valley sub-region.

Exhibit 4.41: Merrimack Valley sub-region Substation Transformer Age Profile

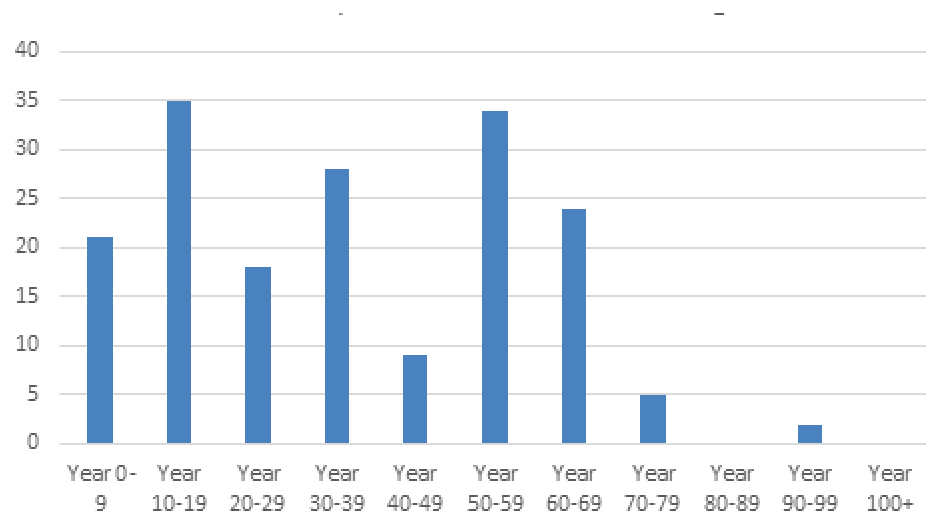


Exhibit 4.42 below shows the distribution pole age profile in the Merrimack Valley sub-region.

Exhibit 4.42: Merrimack Valley sub-region Distribution Pole Age Profile

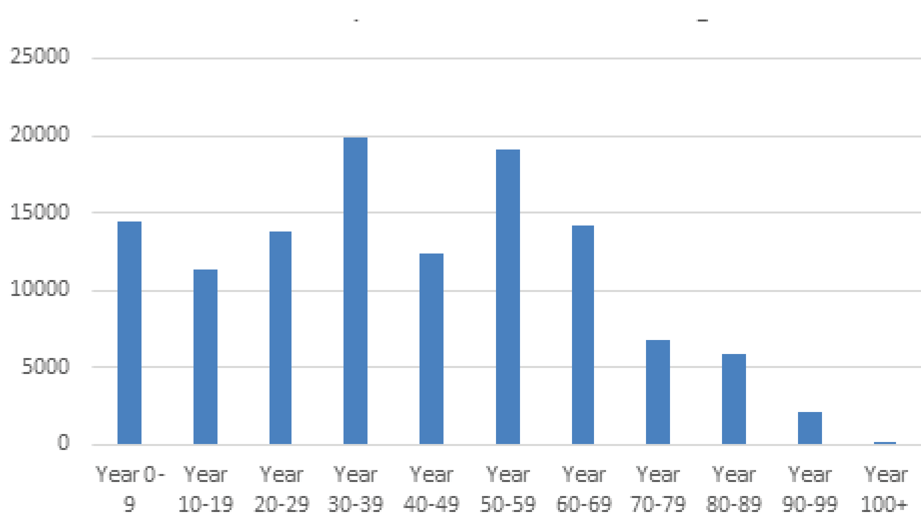
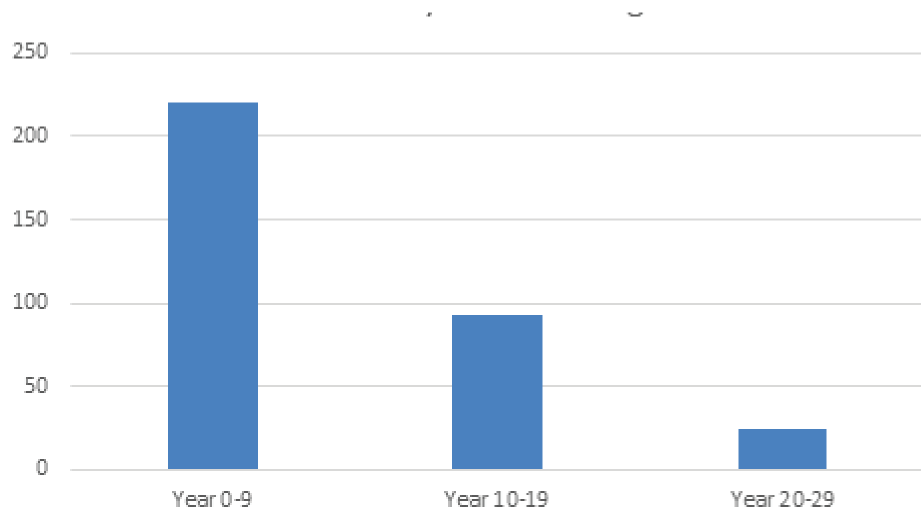


Exhibit 4.43 below shows the recloser age profile in the Merrimack Valley sub-region. Reclosers are further described in Section 4.3.8.

Exhibit 4.43: Merrimack Valley sub-region Recloser Age Profile



4.4.9 Reliability and Resilience

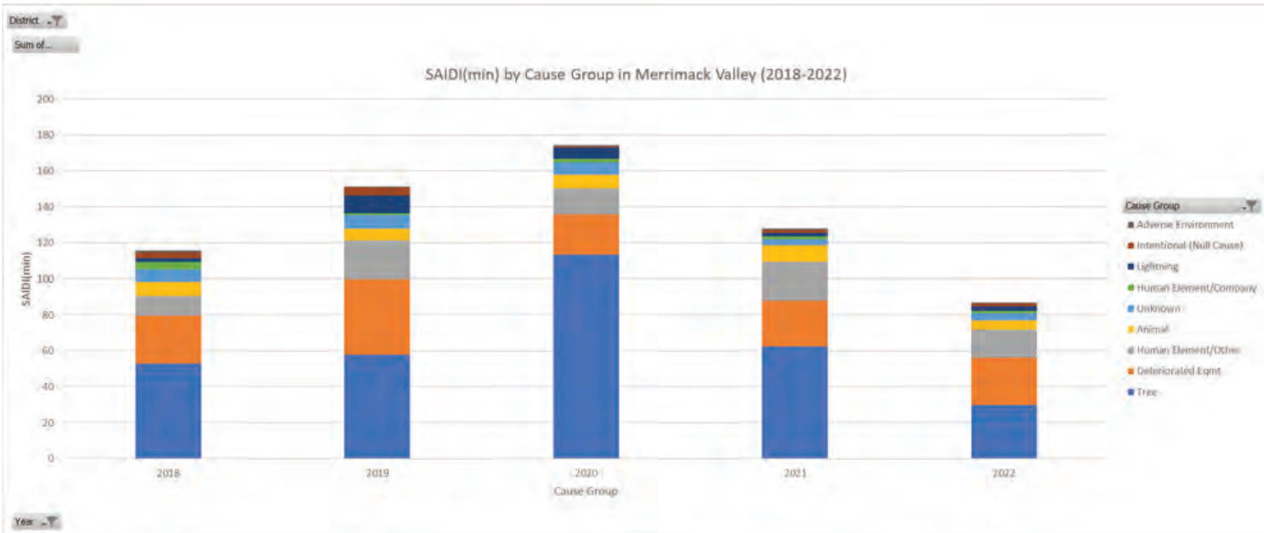
This section will describe how the Company reports reliability and what the current reliability metrics are for this given sub-region. For additional information on reliability, resiliency and company performance, the Company's annual report is here (Department Docket No. 12-120-D). This section is only illustrative for completeness of the system, and as such, relevant reliability investments are defined to be part of "core operations" and additional funding is not proposed in this plan. The investments proposed in the Future Grid Plan are driven by load growth and the need to increase system capacity.

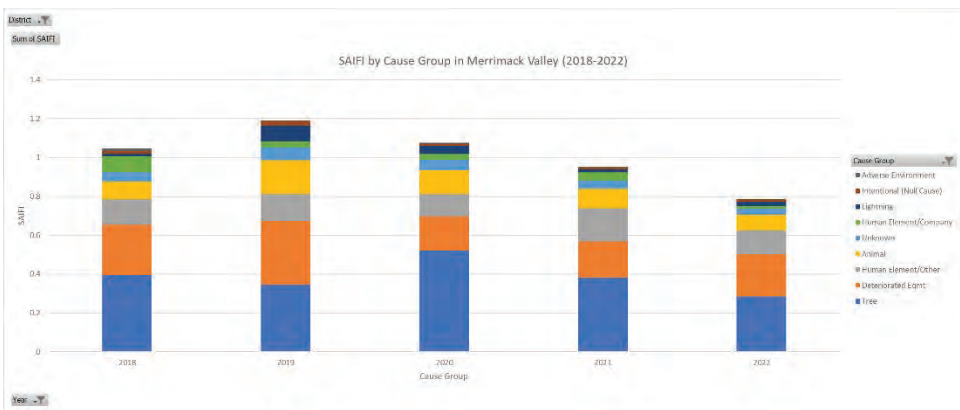
Refer to section 4.3.9 for background on reliability metrics and performance.

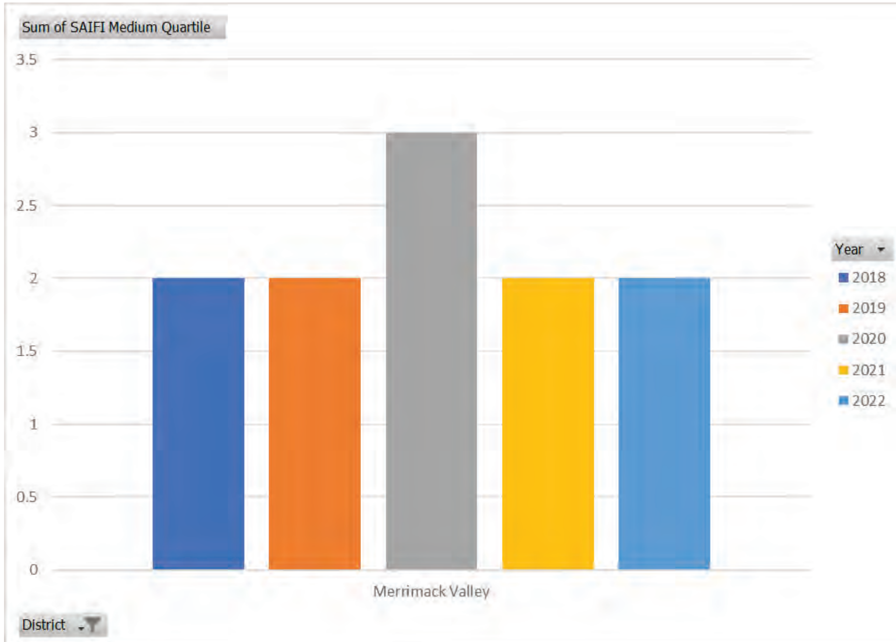
Reliability Performance

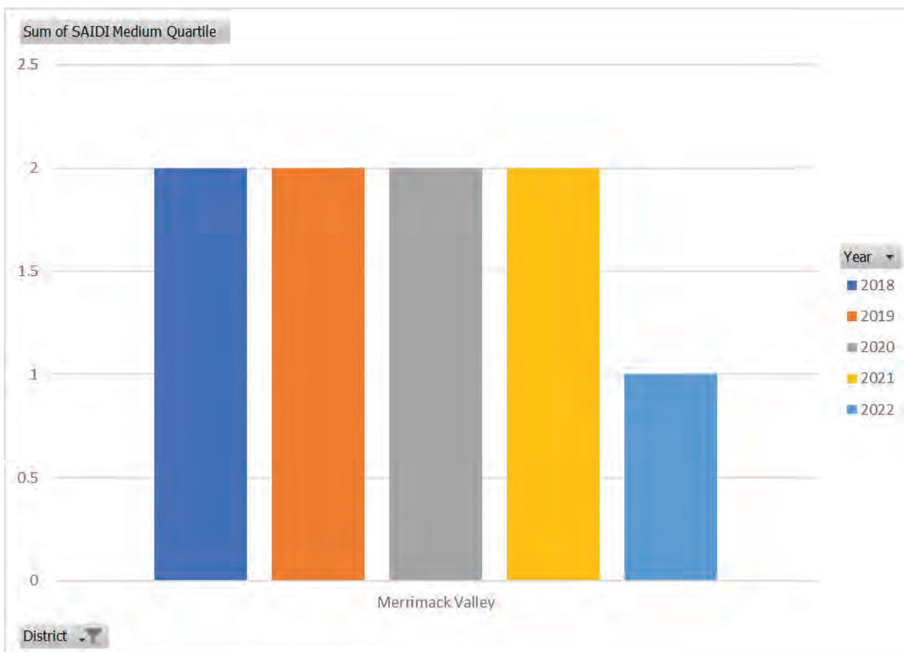
Exhibit 4.44 below show the reliability performance of the sub-region in terms of duration (SAIDI) and frequency (SAIFI) of outages. The data in these Exhibits excludes major events, consistent with the Company's regulatory reporting criteria and call out leading causes of blue-sky outages for the region. Tree-related events caused most outages across this sub-region, in terms of duration and frequency.

Exhibit 4.44: Merrimack Valley sub-region Leading Causes of Blue-Sky Outages and SAIDI and SAIFI Reliability Performance









Refer to section 4.3.9 for background on how reliability metrics are calculated.

The IEEE Guide for Electric Power Distribution Reliability Indices (Standard 1366) was developed to facilitate uniformity in distribution service reliability indices and to aid in consistent reporting practices related to distribution systems, substations, circuits, and defined regions. While this methodology differs from the criteria applied to the Company's regulatory reliability reporting obligations, this approach was utilized to demonstrate the performance of the Company's distinct sub-regions as compared to similar size utilities responding to the survey (>100,000 - <1,000,000 customers). The benchmarking analysis showed that for four out of the last five years, Merrimack Valley has been in the second quartile for frequency of outages (SAIFI) and has been in the first or second quartile for the past five years for duration (SAIDI).

Resiliency Performance

As described in section 4.3.9, outage impacts from major events are traditionally excluded from reliability reporting, as described above. The Company calculated “all-in” SAIDI and SAIFI indices across its service territory to facilitate comparison of the resiliency and reliability challenges experienced in each sub-region relative to the others. This comparison highlights areas where emerging resiliency challenges have been experienced in the past five years. The methodologies that went into these calculations are described in section 4.3.9. Substations may have no reliability data for several reasons, including no recorded events over the time period or if they do not directly serve load to customers.

The following maps illustrate the substation resiliency of this sub-region overlaid with Environmental Justice Areas, as defined by the Commonwealth. The exhibits below show the Company’s distribution substation locations within the given sub-region overlaid with EJCs. Each distribution substation is color-coded indicating its five-year historical SAIDI or SAIFI performance relative to the Company’s entire population of substations. A greater density of distribution substations typically results in shorter distribution feeders with less outage exposure and increased numbers of feeder ties, resulting in better overall reliability. As can be seen in each of these Exhibits, substations in the EJCs fall within the top first and second quartile of SAIDI and SAIFI performance relative to the entire population of the Company’s distribution substations.

Exhibit 4.45: Merrimack Valley sub-region Resiliency in EJCs as shown as SAIDI Substation Performance

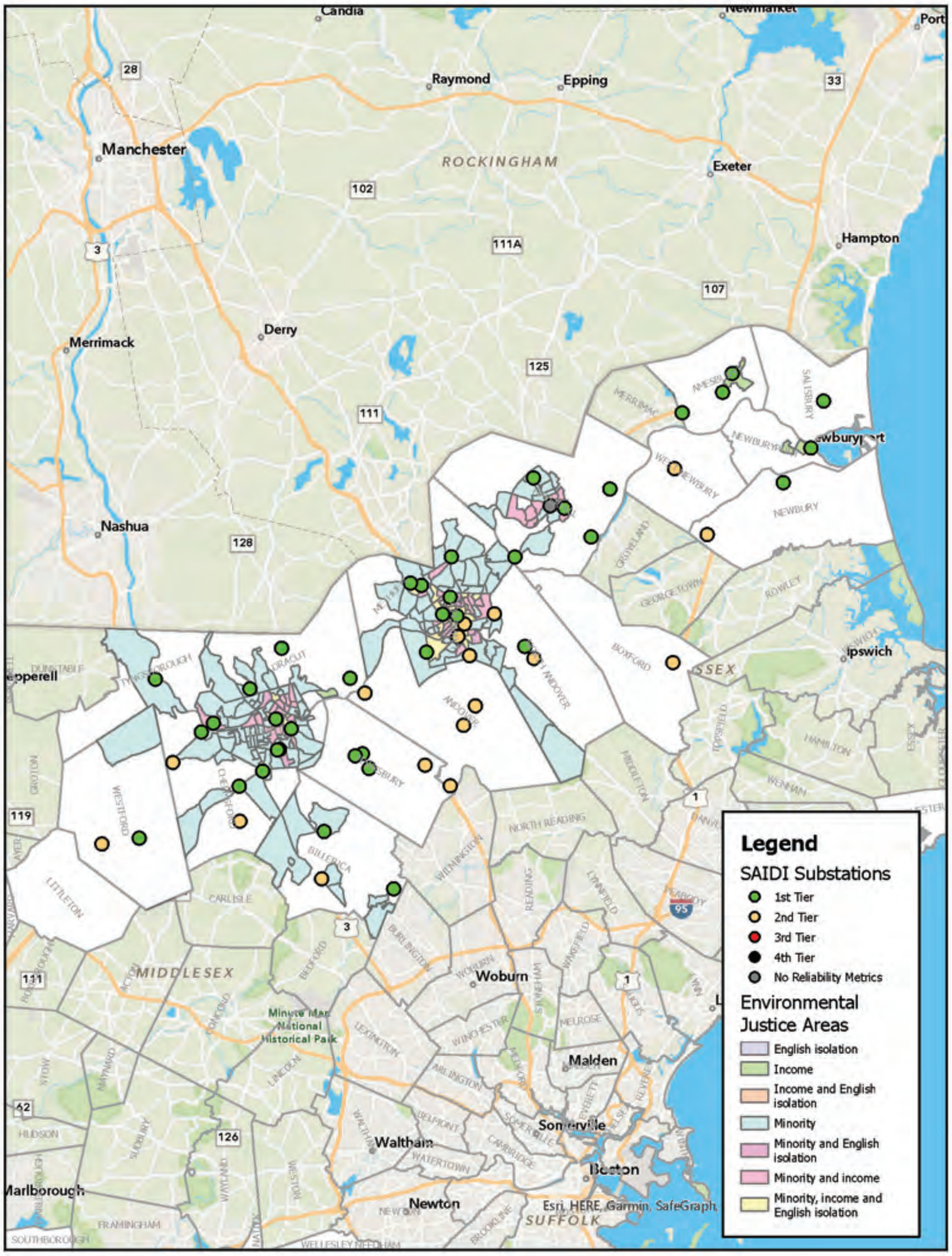
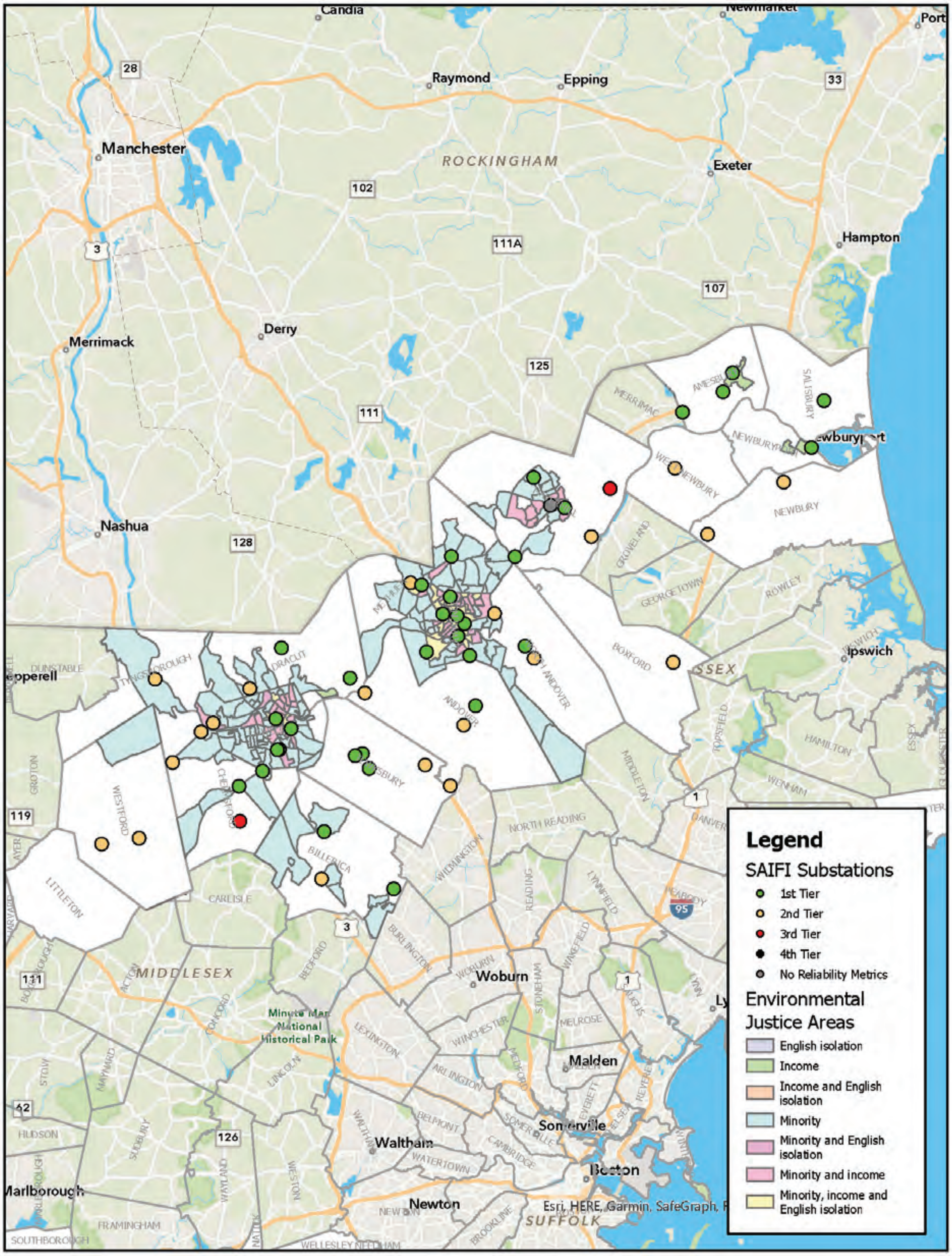


Exhibit 4.46: Merrimack Valley sub-region Resiliency in EJCs as shown as SAIFI Substation Performance



When looking at the 5-year performance, 2020 was particularly a bad year as the Company experienced 18 storm events that were not classified as major events. The impact of each event added together reflects the bad reliability performance at the system level. Also worth noting was that 2018 and 2021 were bad years of performance for the eastern part of the Company's Commonwealth service territory given three back-to-back storms occurring in early 2018 and a Nor'easter occurring in October 2021. As a result, substations in the fourth quartile of SAIDI/SAIFI performance can be seen in South Shore, Southeast and Merrimack Valley region maps.

4.4.10 Siting and Permitting

Energy infrastructure siting and permitting processes are generally consistent across the Commonwealth; therefore, siting and permitting challenges do not vary significantly by region. When projects require considerable underground transmission work, the Energy EFSB review process is triggered to ensure the work is in compliance with State requirements. This EFSB review process is intended to take twelve months (see G.L. c. 164, Section 69J); however, the review timeline for recently submitted transmission line projects is trending toward 30 to 36 months.

Environmentally, the largest differences are at a municipal level rather than regionally. At the project-level, Conservation Commission impacts uniformly across the State but there is a high degree of variability town to town and year to year, which makes it challenging to generalize regionally. Since Merrimack Valley is one of the more developed sub-regions, the Company has faced increased challenges in identifying suitable locations for energy infrastructure given the wetland mitigation requirements for permanently impacted land. Despite this generalization, each site presents different siting and environmental considerations.

4.5 North Shore Sub-Region

The North Shore sub-region in brief:

Nature of the area: The Northshore sub-region is predominantly urban with metropolitan core communities near Boston and sub-regional urban centers in Beverly, Gloucester, Lynn, Peabody, and Salem.

The Company's customers' energy needs, economic circumstances, and demographics in the North Shore sub-region vary greatly, which is why targeted and culturally competent community engagement is at the core of the Company's plan to help the State achieve its goals.

Exhibit 4.47: North Shore sub-region customers by the numbers

Total Customers (Accounts)	% Residential	% Business, Commercial, Municipal, or University	Benefits of EE	Heat Pump Adoption (end of 2022)	Total NG Charging Ports Installed
255,067	88%	12%	1,286,916 MWh	1,399	390 Ports

Exhibit 4.48: North Shore sub-region network by the numbers

Number of Substations	Number of Feeders	Total Length of Feeders	Total peak Load Served	Square Miles of Sub-Region
49	319	2,000 miles	1,107 MW	174

Context of the region

The North Shore is a predominantly urban area which contains a highly integrated network. The North Shore sub-region has low levels of DER penetration in this area relative to other sub-regions due to the lack of large swaths of open space coupled with a network with limited capacity. Due to the dense population and proximity to Boston, the Company anticipates load to grow by approximately 6.6% in the North Shore region in the next 5 years. Additional details can be found in Section 5.

Below are some key characteristics of the North Shore sub-region which will drive future investment needs.

Exhibit 4.49: North Shore Sub-Region Key Characteristics that will Drive Future Investment Needs

Network Characteristic	Consequence
Most of the distribution circuits are a combination of 5 kV (which operate at voltages of 4.16 kV and 2.4 kV) and 15 kV class circuits (which operate at voltages of 13.2 kV or 13.8 kV). There are eighty circuits that operate at 4.16 kV which are supplied from substations that step down the voltage of 23 kV & 13 kV to supply customers. Lower voltages such as 4.16 kV were used more commonly in the past when loads were lower. This 4.16 kV infrastructure is prevalent throughout the North Shore, particularly in urban centers.	Areas served by these lower voltages will largely need to be converted to a higher voltage such as 13.2 kV or 13.8 kV in order to meet the significant load growth that is projected across the State. Voltage conversions can be costly and complex projects, requiring widescale replacement or upgrade of significant amounts of both distribution line and substation facilities.
The 23 kV class subtransmission circuits act both as supplies to substations and to serve mostly larger load customers.	Subtransmission circuits have less capacity than transmission circuits; therefore, load growth on subtransmission-supplied substations can sometimes be limited by the subtransmission feeder supplying it. As a result, the Company will need to invest in both upgrading the substation and extending transmission facilities into these areas to meet the projected load growth.
The Lynn Network no longer meets the needs of the modern distribution system in this area, presenting challenges to provide service to new load and DER customers in areas served by the Network.	The Company has identified the need to contract and eventually eliminate the Lynn Network, replacing it with a radial system with feeder ties more suited to today's needs.
There is extensive underground construction in urban areas.	As capacity limitations are reached on existing underground cables, the ability to increase the size of those cables or install new cables for additional capacity without doing costly civil work to install new duct banks is very limited. This contributes to high-cost distribution line projects when the Company needs to increase the capacity in these areas.

4.5.1 Maps

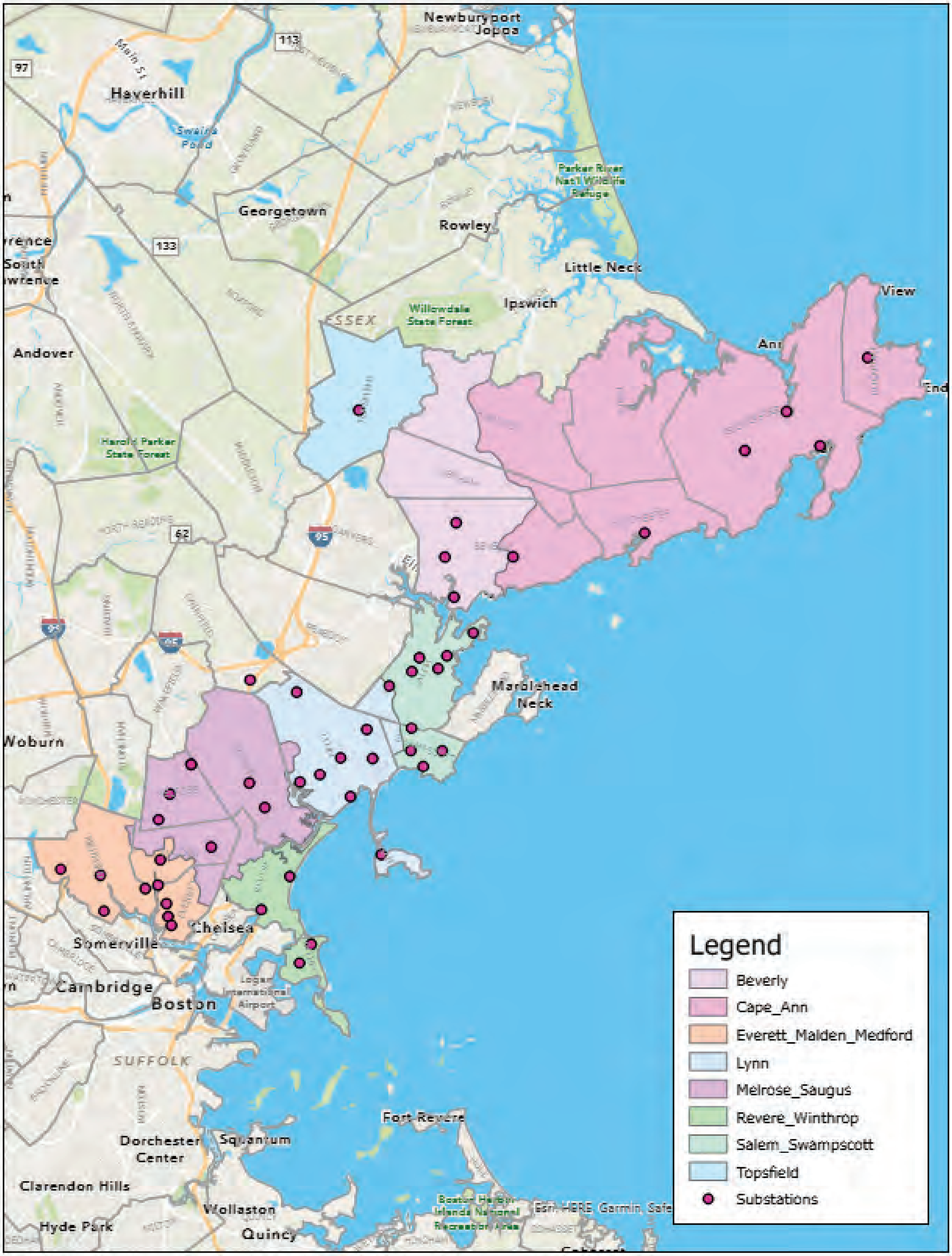
The North Shore sub-region consists of 19 towns and cities and comprises the study areas below.

Exhibit 4.50: North Shore Sub-Region Study Areas and Towns

	Study Area	Town
1	Cape Ann	Beverly, Essex, Gloucester, Hamilton, Manchester, Rockport, Wenham
2	Beverly	Beverly, Hamilton, Wenham
3	Everett/Malden/Medford	Everett, Malden, Medford
4	Lynn	Lynn, Nahant, Salem, Saugus, Swampscott
5	Melrose/Saugus	Everett, Lynn, Malden, Medford, Melrose, Revere, Saugus
6	Revere/Winthrop	Revere, Winthrop
7	Salem/Swampscott	Salem, Swampscott
8	Topsfield	Topsfield

Exhibit 4.51 below shows the substation locations within the North Shore sub-region's study areas, indicated with a red dot. Not all study areas cleanly follow town lines because they are defined electrically instead of geographically. Many of the locations of substations in the North Shore sub-region were driven by residential and commercial property development. Strong economic development activity has continued in these areas due to their proximity to public transit systems and available labor pools, as well as builder interest in unused or limited use waterfront parcels for mixed-use development.

Exhibit 4.51: North Shore sub-region Substation Locations and Study Areas



4.5.2 Customer Demographics

Exhibit 4.52: North Shore sub-region customer demographics summary

Number of Customers				Residential Population Growth	Benefits of EE	Existing Connected Rooftop DER (< 25kW)
Total	Residential – Total	Residential – Low Income Rate Participants	Commercial	5-year Growth Projections		
255,067	223,379	26,892	31,688	1.6%	1,286,916 MWh	82 MW

The Company serves a total of 255,067 customers (defined by individual accounts, not the number of people served) – in the North Shore sub-region. Approximately 88% (223,379) of these customers are residential customers and the other 12% are comprised of commercial, municipal, or university customers.

In addition to the Mass Save programs, which have benefited customers in the North Shore sub-region, 24 towns statewide have been identified for targeted outreach per the MA EEAC Equity Working Group plans. Under these outreach plans, the Company is specifically working to encourage more Energy Efficiency benefits in low-adoption zones. The towns/cities included in the North Shore sub-region are Everett, Lynn, Malden, Revere, and Saugus.

The Company recognizes that a significant portion of the Company's customers live in EJCs, which are disbursed throughout the Company's service area. Historically, EJCs have borne the highest energy burdens and been disproportionately impacted by the fossil-based economy. As outlined earlier in Section 3.3, the Company is developing a formal Equity and Environmental Justice Policy and Engagement Framework, as well as complementary policy and framework focused on Indigenous Peoples, which the Company will seek feedback on from those communities prior to finalizing, please refer to the Appendix for those drafts.

Below please see Exhibit XX which overlays the Commonwealth EJC map with the Company's current substations.[18]

[18] Multiple substations in close proximity with one another may appear to be overlapping or as one dot on this map

Exhibit 4.53: North Shore sub-region substations with to the Commonwealth's EJC map

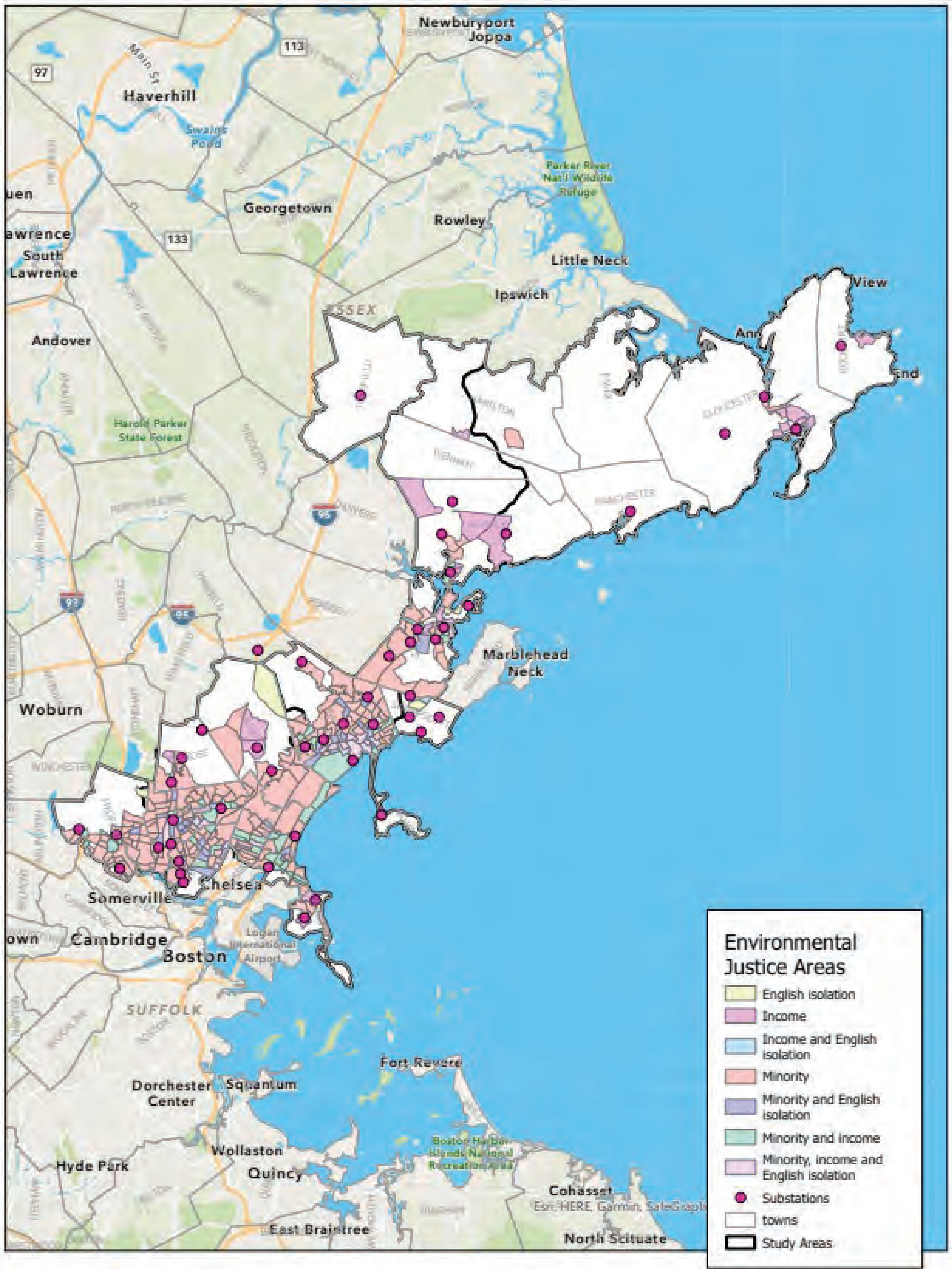


Exhibit 4.53 above highlights concentrations of substations in many load-dense areas – town centers and other major economic areas with existing industry, or a history of industry. Load density and electric capacity needs are the key drivers to substation density and location. As the load increases, the need for more substations to serve these population centers and expanding rural areas will increase as well. Many EJCs have been identified as such by the Commonwealth because they have been historically unduly burdened by infrastructure and related pollution. As discussed in Section 3, the Company is committed to being a trusted partner with all of the Company's host communities, including those which contain EJCs, as new infrastructure needs to be built throughout the Commonwealth to reach decarbonization and electrification goals. Additional infrastructure that has yet to be built per recommendations in this Future Grid Plan can be found in Section 6.

4.5.3 Economic Development

The development of the Company's Grid Future Plan was informed, in part, by the varying levels of readiness within each sub-region. Within the Company's study areas defined in the Future Grid Plan, 14 communities have completed decarbonization plans and 139 are designated as "green communities" under M.G.L. c. 25A §10. In partnership with the Company, the following municipalities have completed a Strategic Energy Management Plan (SEMP): Athol, Beverly, Everett, Lowell, Melrose, Newburyport, and Salem. The Company anticipates one new SEMP to be signed before the end of the year, with an additional five SEMPs in the development queue.

In the North Shore sub-region, five communities (Beverly, Medford, Melrose, Salem, and Swampscott) have completed decarbonization plans, and 18 are designated as green communities. Four of the communities, in partnership with the Company, have completed an SEMP. The region is currently engaging with the MMA Economic Development Planning Council to develop a comprehensive strategy; however, understood concerns include climate resilience and flood mitigation. Additionally, the region aspires to foster increased commercial development opportunities and promote affordable housing.

4.5.4 Electrification Growth

Heat Electrification - The North Shore region has moderate heat pump adoption among the six regions with about 1,000 units adopted by the end of 2022.

Transport Electrification – There has been significant growth in the LDEV sales in the North Shore sub-region with about 5,500 vehicles as of the end of 2022, making the North Shore the sub-region with the highest EV count. However, the total number of MHDEVs is less than 10, indicating very low penetration at present, like other sub-regions. Since 2019, the Company has installed 390 EV charging ports via their phase I and phase II EV charging programs in the North Shore region.

4.5.5 DER Adoption (Battery Storage and Solar Photovoltaic)

With a total of 142 MW of generation connected, the North Shore sub-region has relatively low DER penetration. Somewhat similar to the Merrimack Valley sub-region, this low penetration has to do with the limited capacity on the network coupled with the lack of abundant open space to install large facilities. Connected DER is predominately solar, representing 87% of the installed DER capacity in the sub-region.

Exhibit 4.54: North Shore sub-region DER Adoption Summary

Sub-Region	Solar (MW)	Battery (MW)	Hydro (MW)	Wind (MW)	Miscellaneous[1] (MW)	Grand Total (MW)
North Shore - Connected DER	121.6	5.0	0.0	7.3	18.3	152.2

The past decade has seen tremendous growth in DER connections in the North Shore sub-region. Note that in the exhibits below, the 2023 value is reflective of cumulative interconnections as of July 2023.

Exhibit 4.55: North Shore sub-region Cumulative Connected Generation and Storage

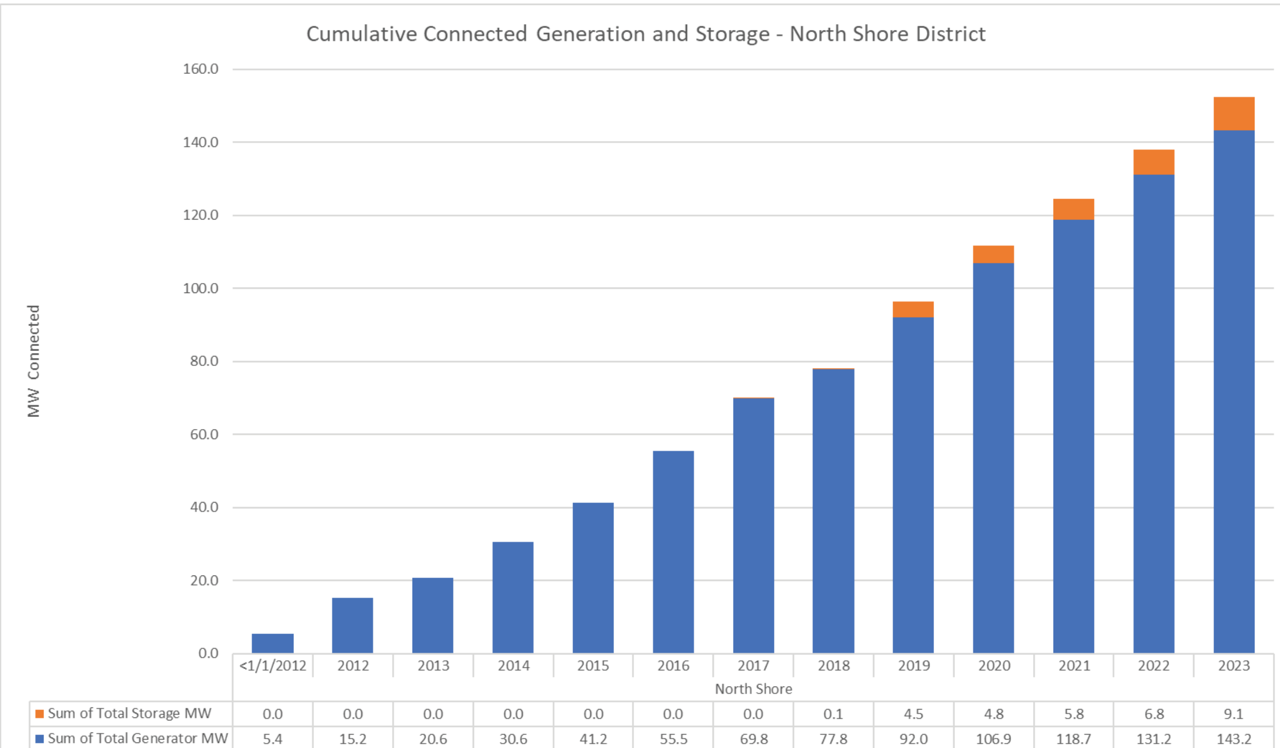


Exhibit 4.56 contains visibility of the current DER interconnection queue in the North Shore sub-region. Recent application trends have demonstrated a shift from largely solar PV applications to mainly battery storage, with batteries representing 73% of the current queued DER capacity.

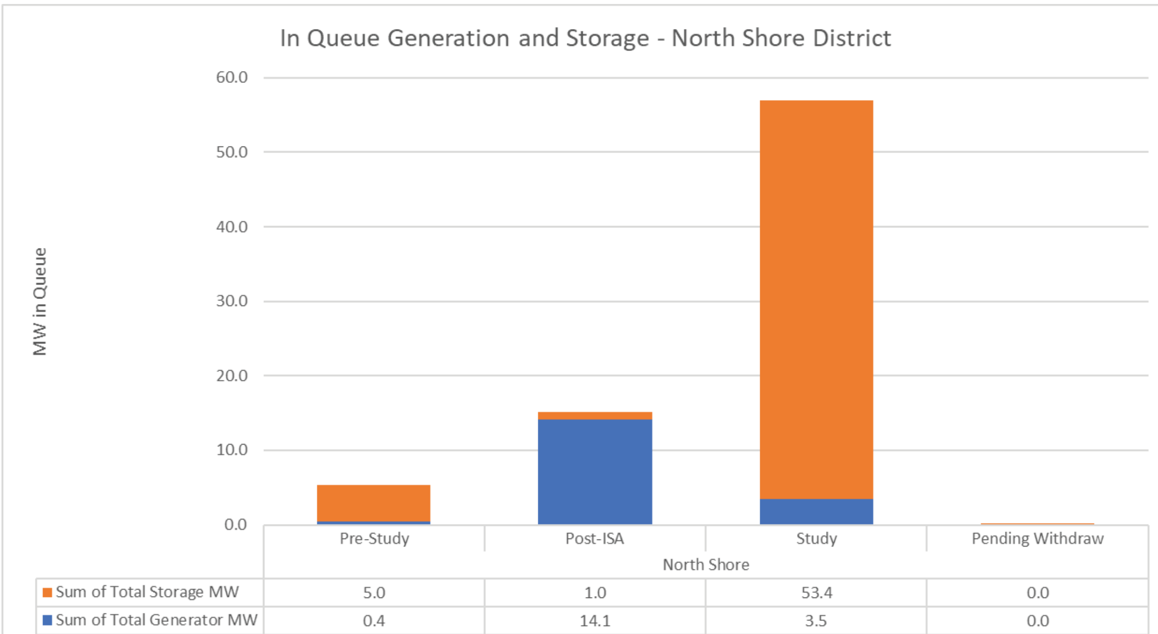
A large majority of the batteries are stand-alone, albeit some are co-located as PV paired with storage. Unlike other forms of DER, which operate solely in a discharge or export capacity, contributing power to the grid, standalone batteries also must charge from the grid. While solar and other forms of DER, excluding batteries, only require there to be sufficient grid *hosting* capacity for their interconnection, batteries require both hosting and load-serving capacity at the location of their interconnection. Therefore, batteries are subject to capacity deficiency (i.e., charge) considerations such as those highlighted in Section 4.5.7 as well as any hosting capacity (i.e., discharge) constraints that may be present.

This significantly increases the complexity of planning and operating the network.

Exhibit 4.56: North Shore sub-region pending DER summary in queue

Sub-Region	Solar (MW)	Battery (MW)	Hydro (MW)	Wind (MW)	Miscellaneous[2] (MW)	Grand Total (MW)
North Shore - Pending DER	16.13	59.4	0.0	0.0	2.0	77.5

Exhibit 4.57: North Shore sub-region pending DER Generation and Storage in queue



Combining the 77.5MW of DER in the interconnection queue, and the 152.2MW already connected in the North Shore sub-region, the total for the area would be 229.7MW if all in-queue projects move forward. While it is unlikely that all will connect, this would be a doubling of interconnected DER in an already constrained area and would therefore require significant infrastructure expansion. Layering on the complexity of battery operation and solar variability, advanced grid management tools will be necessary in addition to the infrastructure build out to maintain the safety and reliability of the grid.

In the North Shore sub-region, the Company has analysis completed or in progress for group study for the interconnection of DER in the following study areas[3]:

- Beverly

The proposed DER and system modifications required for the proposed groups have been included in the base case for this Future Grid Plan analysis; should the DER customers in these groups not proceed to interconnection, the investments described in will need to be analyzed for the impacts of this attrition and adjusted appropriately. The Company is proposing to apply CIP cost allocation principles to these investments once they reach sufficient maturity.

The high-level benefits of the CIPs to distribution customers include:

- Reliability: the solution proposed to safely and reliably interconnect group study DER, in many cases coincidently, addresses existing or projected system needs. The proposed upgrades, if approved, expedite addressing these reliability concerns. These include:

- EPS normal configuration thermal loading
    - EPS contingency configuration customer unserved
    - EPS asset conditions
- Enabled electrification: the proposed solution in some cases also provides thermal capacity beyond the planning horizon and supports some loading projects out to 2050.
- Reserved Small DG: the proposed solutions also incorporate a reserved capacity on each study feeder for the small rooftops to interconnect without triggering major EPS upgrades, which typically is a direct benefit to distribution customers.

The high-level description of the common system modifications required to accommodate the interconnection of the DER included in the groups listed above are included in the Appendix. Note that these areas are in various stages of maturity and the modifications identified below are subject to change pending further analysis through the group study process. Cumulatively, in order to interconnect the 25 MW of DER proposed through the current group studies, the Company anticipates requiring system modifications that include the addition or upgrade of 3 substation transformers and approximately 4 miles of distribution line construction, at an estimated cost of $70M.

4.5.6 Grid Services (Demand Response, Smart inverter Controls, Time-varying Rates)

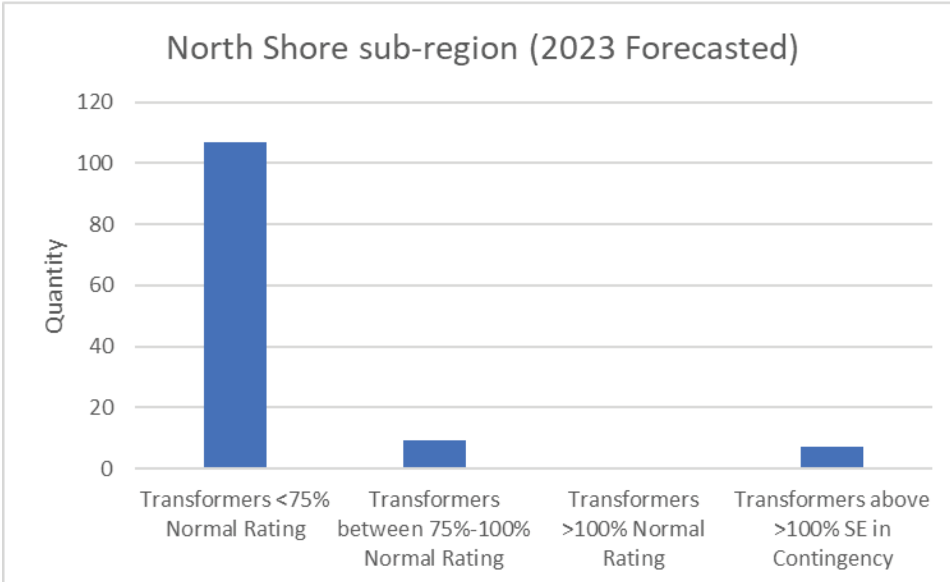
The Company currently offers several grid service participation opportunities to residential and commercial customers through its Demand Response and EV managed charging programs. Customers can earn incentives for curtailing load, pre-cooling with smart thermostats, charging their electric vehicles at optimal times, or shifting energy use with battery storage during peak load periods. As described in sections 6.3, 6.11, and 9.3 and 9.6 the Company is also on a path toward expanding grid services via AMI and time-varying rates, and leveraging DERMS technology investments to offer more dynamic, location-specific grid services as NWA solutions in the future.

In the North Shore region over 6,000 customers currently participate in ConnectedSolutions DR program and help to reduce approximately 28 MW of load on the grid when the overall grid is at peak. This has helped to delay investments and maximize the utilization of the current network.

4.5.7 Capacity Deficiency

The graphs below summarize the asset loading across the North Shore sub-region in 2023. The 2023 loading profile shows that most assets are loaded below 75% of their normal rating.

Exhibit 4.58: North Shore sub-region 2023 Forecasted Transformer Loading Profile



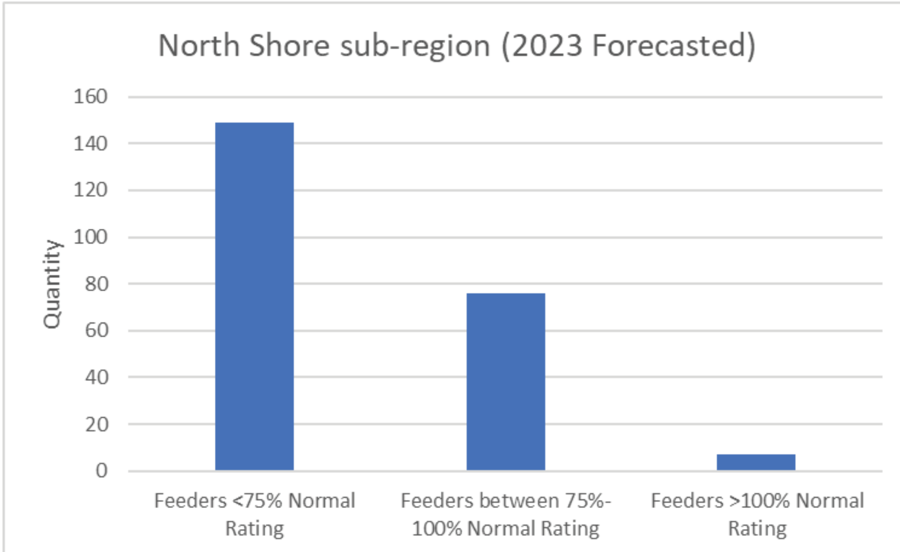
Substation transformer capacity deficiencies exist in the following areas:

Exhibit 4.59: North Shore sub-region 2023 Forecasted Transformer capacity deficiencies

Study Area	Substation	Capacity Deficiency
Cape Ann	Riverdale 52	Transformers > 100% Emergency Rating in Contingency
Revere Winthrop	Revere 7	Transformers > 100% Emergency Rating in Contingency
Cape Ann	East Beverly 51	Transformers > 100% Emergency Rating in Contingency
Salem Swampscott	West Salem 29	Transformers > 100% Emergency Rating in Contingency
Melrose Saugus	Maplewood 16	Transformers > 100% Emergency Rating in Contingency

There are operational protocols that go into effect to manage the risk of overloading of transformers upon a contingency event (e.g., the loss of a neighboring transformer).

Exhibit 4.59: North Shore sub-region 2023 Forecasted Feeder Loading Profile



Seven feeders in the North Shore sub-region have an identified existing capacity deficiency; these deficiencies are being monitored as anticipated spot loads come into service, and operational mitigations will manage the overloads as appropriate.

Much of the North Shore sub-region borders the ocean, and geographical constraints can complicate solution development in this area. The Cape Ann area is currently served by a mix of 34.5 kV and 23 kV subtransmission lines, since transmission does not extend any further east than Beverly. These lower voltage subtransmission lines have less load-serving capacity than higher voltage transmission lines would be capable of providing to the area.

The North Shore sub-region includes 28 substations which step the voltage down from 34.5kV or 23 kV to a mixture of 13 kV and 4.16 kV, some of which have contingency loading and voltage performance concerns that limit the amount of load growth that can be supported by these substations.

The North Shore sub-region features 147 circuits that are 4.16 kV, which are mainly located in urban settings. These circuits have limited capacity and are primarily located in urban areas with significant amounts of underground infrastructure. Converting underground facilities to a higher voltage to achieve greater capacity can come at significant cost.

4.5.8 Aging Infrastructure

This section is only illustrative for completeness of the system, and as such, relevant aging infrastructure investments are defined to be part of “core operations” and additional funding is not proposed in this plan. The investments proposed in this Future Grid Plan are driven by load growth and the need to increase system capacity.

As energy infrastructure ages, and often consequently, its condition worsens, the risk of equipment failure increases and the reliability of operation decreases. The age of infrastructure is an important consideration when assessing the condition of assets and in efforts to meet the future demands of the network. However, asset replacement is driven primarily by asset condition rather than time of life. The Company’s approach to maintenance has moved from a time-based approach to risk and condition based as a result of digitizing information and having real-time data. Substations and distribution lines are surveyed regularly to assess asset health and to make recommendations for replacement.

Assets are rated based on a range of criteria on their asset health, which drives asset condition replacement projects. Standard maintenance and regular testing (e.g., inspecting and replacing subcomponents of a circuit breaker) can enhance reliability and extend the life of specific assets. Often, assets exceed their life expectancy if their condition and risk profile allow it, enabling the Company to maximize the value of assets while maintaining network reliability.

Additionally, as the Company moves towards modernizing and standardizing the Company's grid and/or substations, existing equipment may need to be modified or replaced in order to digitize the Company's methods. It is important that the Company remains diligent in improving infrastructure with new technologies and remains environmentally focused. (e.g., changing substation support structure design from aluminum to steel due to efficiencies and decarbonization).

Exhibit 61 shows the metal clad age profile in the North Shore sub-region. Metalclads are further described in Section 4.3.8.

Exhibit 4.61: North Shore sub-region Metalclad Age Profile

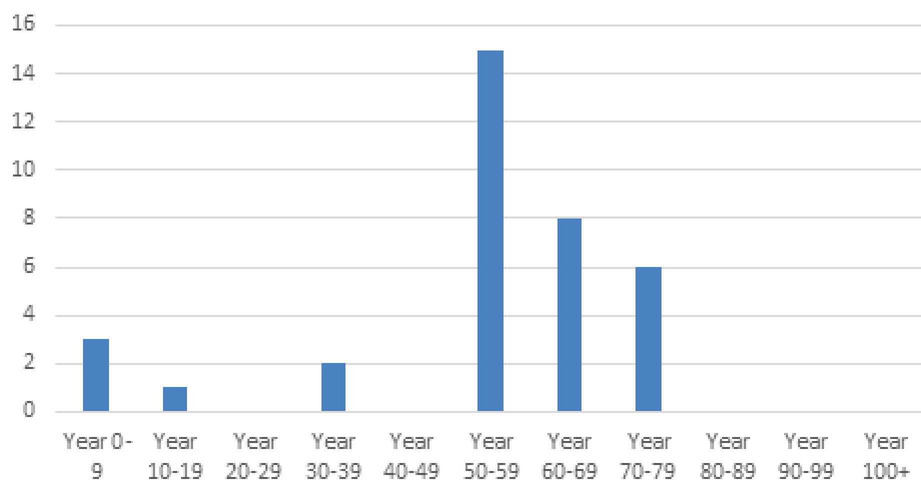


Exhibit 4.62 shows the substation transformer age profile in the North Shore sub-region.

Exhibit 4.62: North Shore sub-region Substation Transformer Age Profile

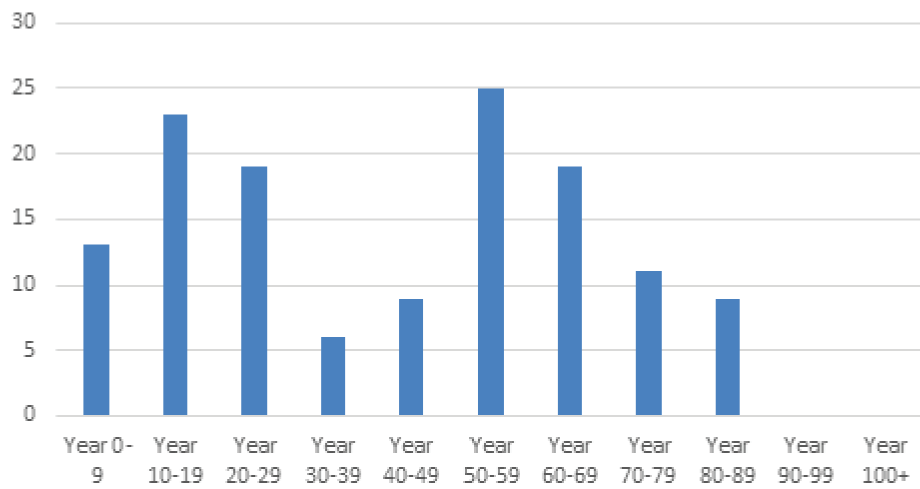


Exhibit 4.63 shows the distribution pole age profile in the North Shore sub-region

Exhibit 4.63: North Shore sub-region Distribution Pole Age Profile

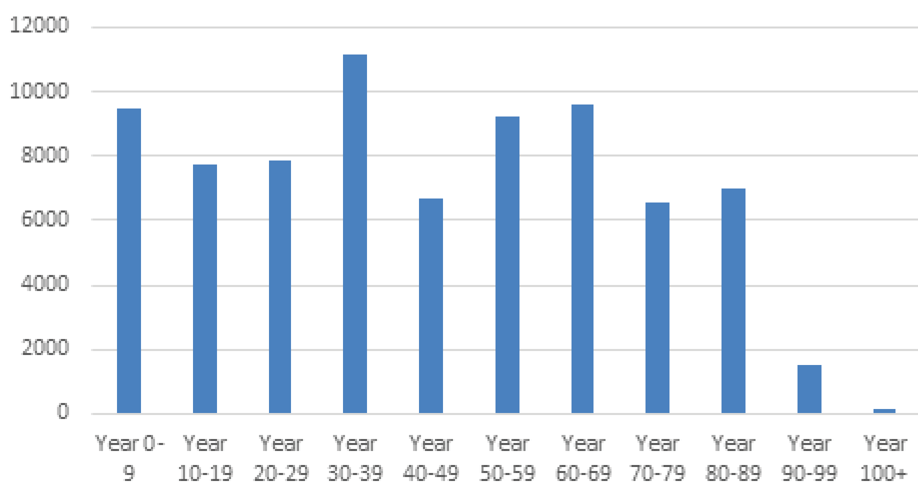
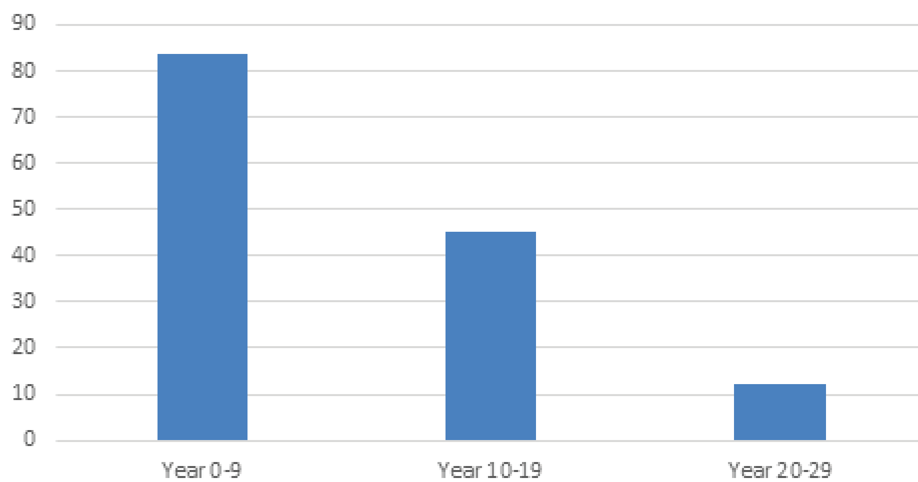


Exhibit 4.64 shows the recloser age profile in the North Shore sub-region.

Exhibit 4.64: North Shore sub-region Recloser Age Profile



4.5.9 Reliability and Resilience

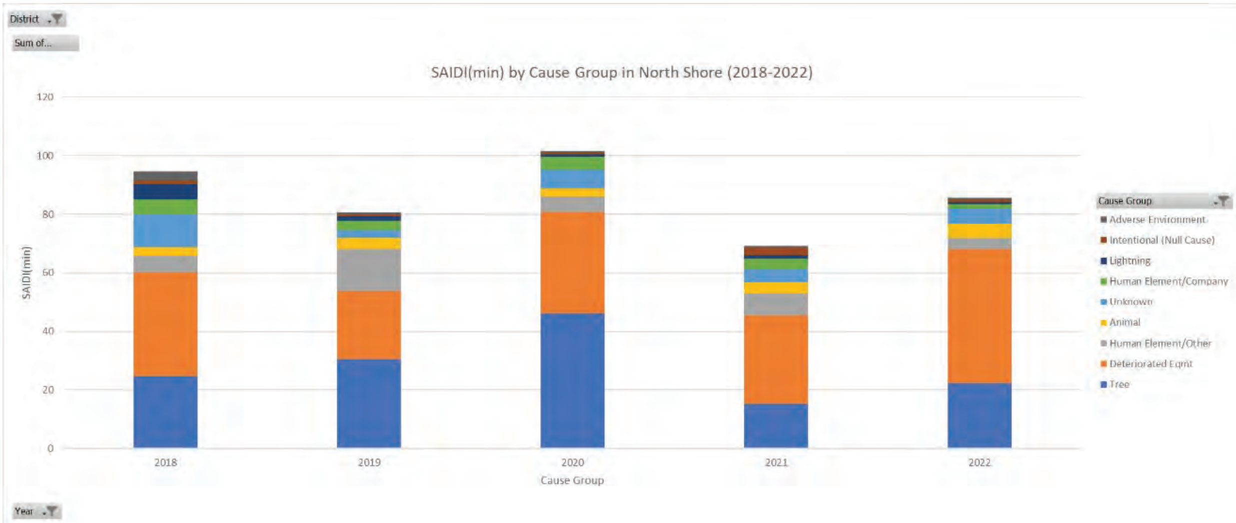
This section will describe how the Company reports reliability and what the current reliability metrics are for this given sub-region. For additional information on reliability, resiliency and company performance, the Company's annual report is here (Department Docket No. 12-120-D). This section is only illustrative for completeness of the system, and as such, relevant reliability investments are defined to be part of "core operations" and additional funding is not proposed in this plan. The investments proposed in the Future Grid Plan are driven by load growth and the need to increase system capacity.

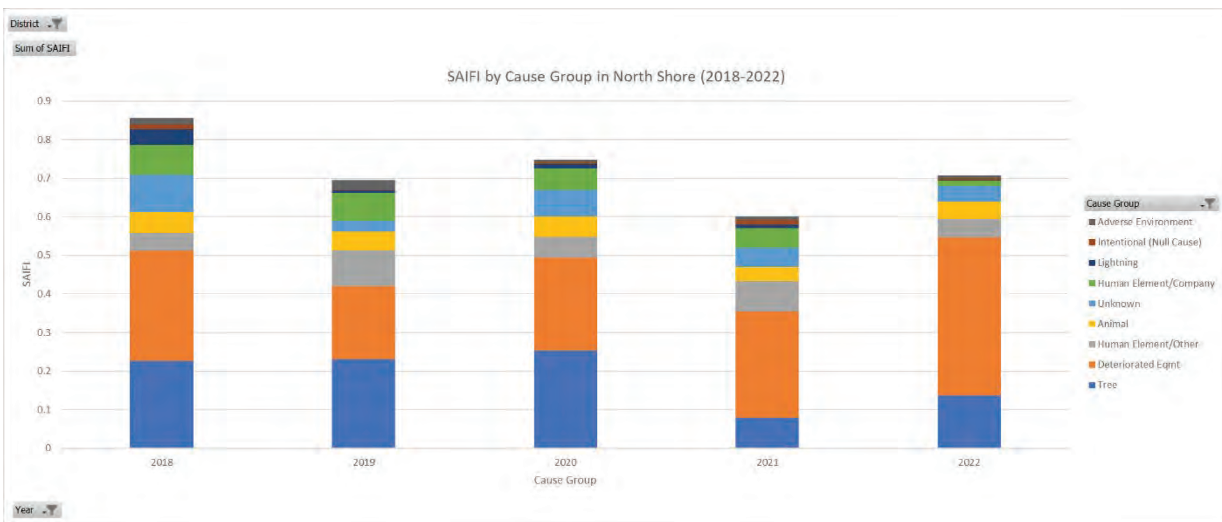
Refer to section 4.3.9 for background on reliability metrics and performance.

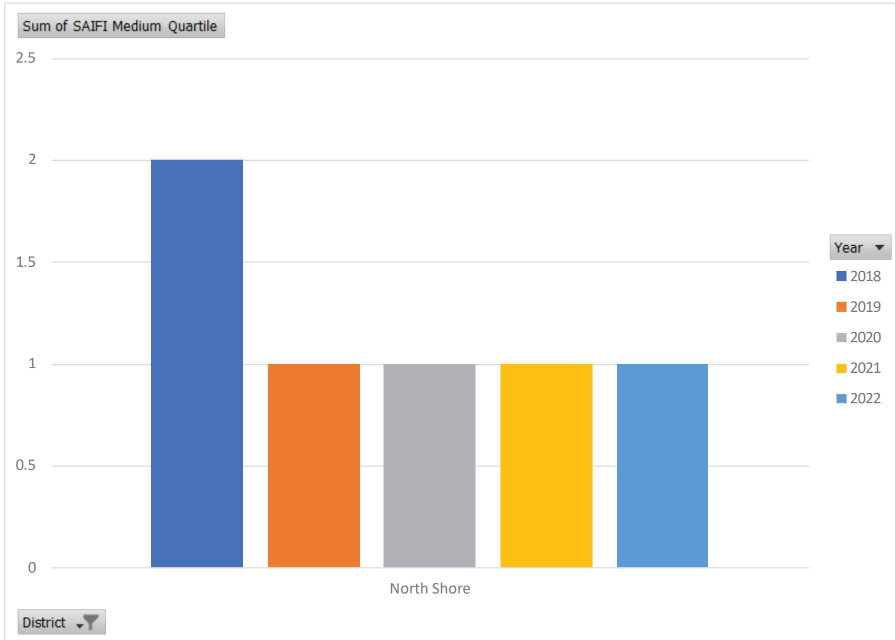
Reliability performance

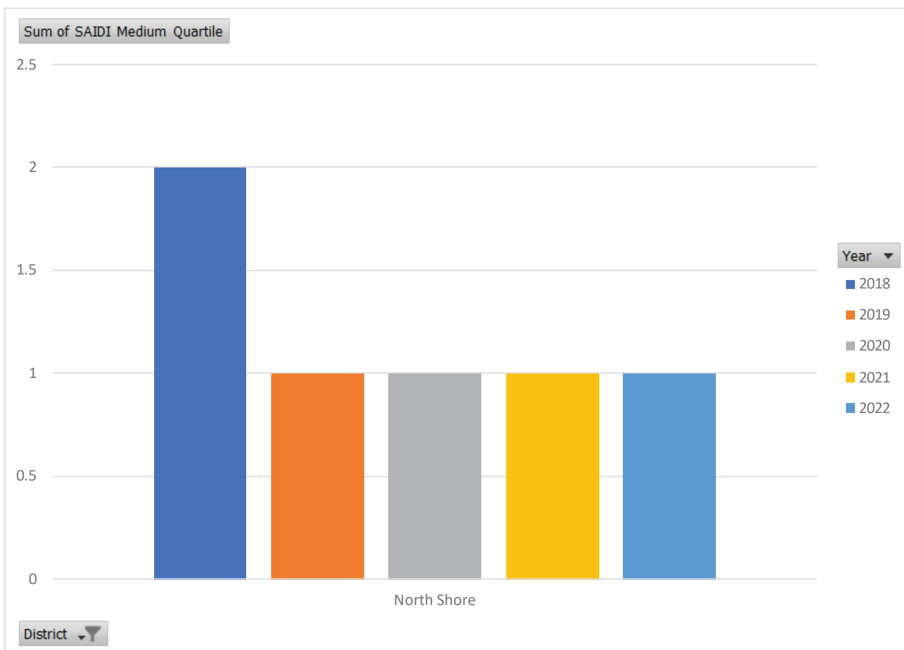
The exhibits below show the reliability performance of the sub-region in terms of duration (SAIDI) and frequency (SAIFI) of outages. The data in these Exhibits excludes major events, consistent with the Company's regulatory reporting criteria and call out leading causes of blue-sky outages for the region. Tree-related events and deteriorating equipment (due to a larger portion of undergrounded distribution in this region) caused the majority of outages across this sub-region, in terms of duration and frequency.

Exhibit 4.65: North Shore sub-region Leading Causes of Blue-Sky Outages and SAIDI and SAIFI Reliability Performance









Refer to section 4.3.9 for background on how reliability metrics are calculated.

The IEEE Guide for Electric Power Distribution Reliability Indices (Standard 1366) was developed to facilitate uniformity in distribution service reliability indices and to aid in consistent reporting practices related to distribution systems, substations, circuits, and defined regions. While this methodology differs from the criteria applied to the Company's regulatory reliability reporting obligations, this approach was utilized to demonstrate the performance of the Company's distinct sub-regions as compared to similar size utilities responding to the survey (>100,000 - <1,000,000 customers). The benchmarking analysis showed that for the last four years, North Shore has been in the first quartile for frequency of outages (SAIFI) and has been in the first quartile for the past four years for duration (SAIDI).

Resiliency performance

As described in section 4.3.9, outage impacts from major events are traditionally excluded from reliability reporting, as described above. The Company calculated “all-in” SAIDI and SAIFI indices across its service territory to facilitate comparison of the resiliency and reliability challenges experienced in each sub-region relative to the others. This comparison highlights areas where emerging resiliency challenges have been experienced in the past five years. The methodologies that went into these calculations are described in section 4.3.9. Substations may have no reliability data for several reasons, including no recorded events over the time period or if they do not directly serve load to customers.

The following maps illustrate the substation resiliency of this sub-region overlaid with EJCs, as defined by the Commonwealth. The exhibits below show the Company’s distribution substation locations within the given sub-region overlaid with EJCs. Each distribution substation is color-coded indicating its five-year historical SAIDI or SAIFI performance relative to the Company’s entire population of substations. A greater density of distribution substations typically results in shorter distribution feeders with less outage exposure and increased numbers of feeder ties, resulting in better overall reliability.

Exhibit 4.66: North Shore sub-region Resiliency in EJCs as shown as SAIDI Substation Performance

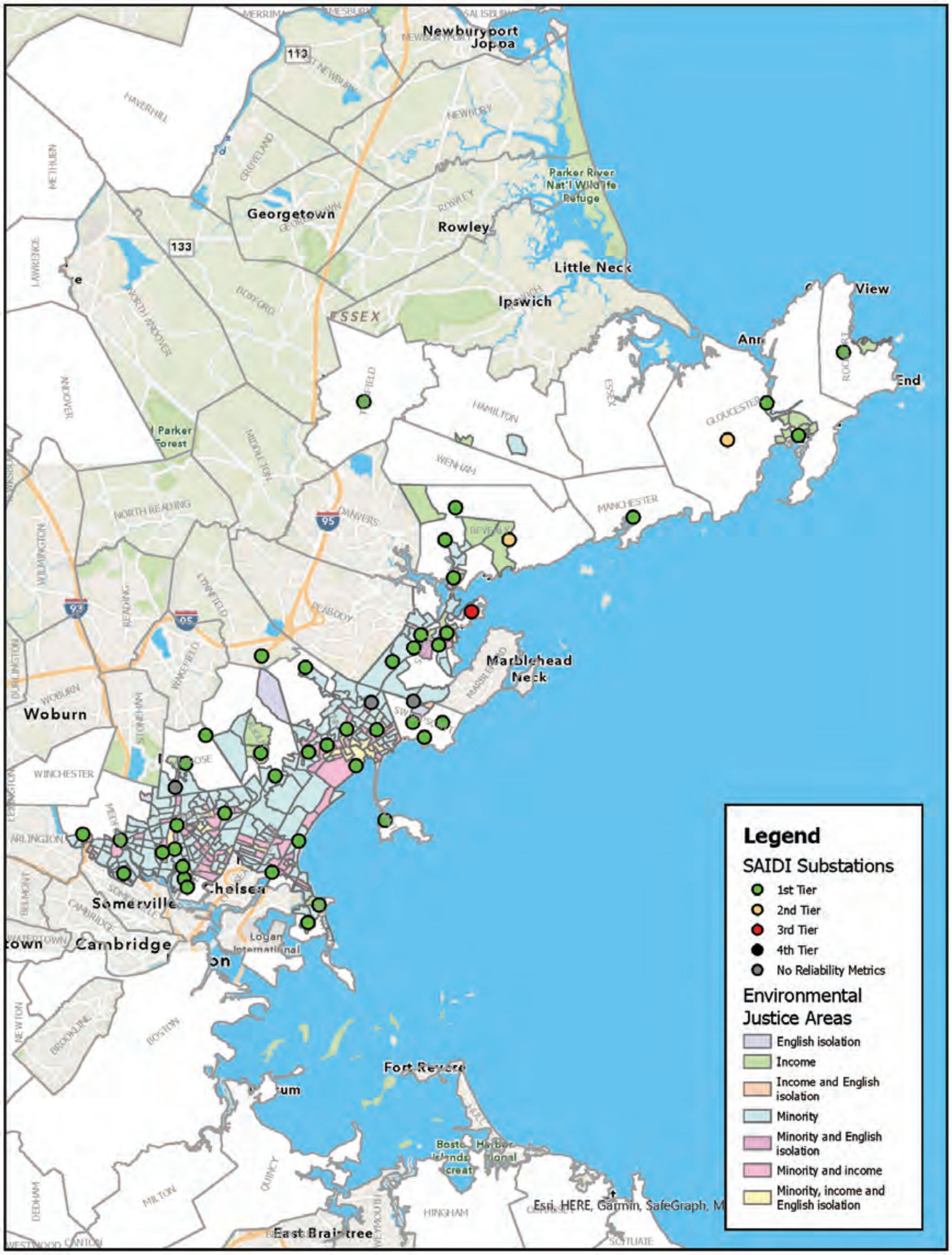
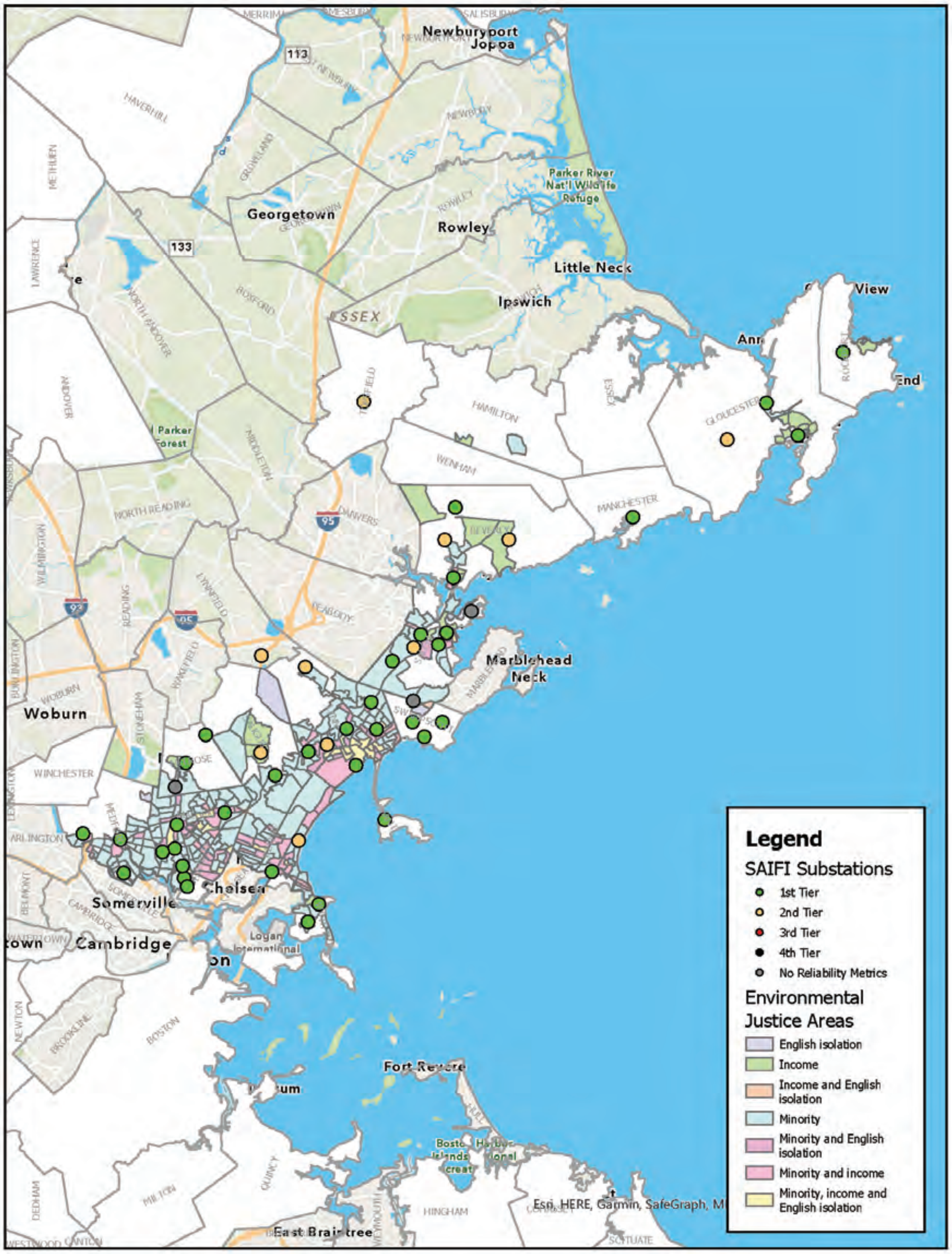


Exhibit 4.67: North Shore sub-region Resiliency in EJCs as shown as SAIFI Substation Performance



When looking at the 5-year performance, 2020 was a particularly bad year as the Company experienced 18 storm events that were not classified as major events. The impact of each event added together reflects the bad reliability performance at the system level. Also worth noting was that 2018 and 2021 were bad years of performance for the eastern part of the Company's Commonwealth service territory given three back-to-back storms occurring in early 2018 and a Nor'easter occurring in October 2021. As a result, substations in the fourth quartile of SAIDI/SAIFI performance can be seen in South Shore, Southeast and Merrimack Valley region maps.

4.5.10 Siting and Permitting

Energy infrastructure siting and permitting processes are generally consistent across the Commonwealth; therefore, siting and permitting challenges do not vary significantly by region. When projects require considerable underground transmission work, the EFSB review process is triggered to ensure the work is in compliance with State requirements. This EFSB review process is intended to take twelve months (see G.L. c. 164, Section 69J); however, the review timeline for recently submitted transmission line projects is trending toward 30 to 36 months.

Environmentally, the largest differences are at a municipal level rather than regionally. At the project-level, Conservation Commission impacts uniformly across the State but there is a high degree of variability town to town and year to year, which makes it challenging to generalize regionally.

Since the North Shore sub-region is one of the more developed regions, the Company has faced increased challenges in identifying suitable locations for energy infrastructure. Each site presents different siting and environmental considerations, especially given the wetland mitigation requirements for permanently impacted land.

4.6 Southeast Sub-Region

The Southeast sub-region in brief:

Nature of the area: The Southeast sub-region is predominantly suburban with urban centers in Milford, Attleboro, Fall River, and Somerset.

The Company's customers' energy needs, economic circumstances, and demographics in the Southeast sub-region vary, which is why targeted, and culturally competent community engagement is at the core of the Company's plan to help the State achieve its goals.

Exhibit 4.68: Southeast sub-region customers by the numbers

Total Customers (accounts)	% Residential	% Business, Commercial, Municipal, or University	Benefits of EE	Heat Pump Adoption (end of 2022)	Total NG Charging Ports Installed
231,799	87%	13%	1,169,519 MWh	3,300	390 Ports

Exhibit 4.69: Southeast sub-region network by the numbers

Number of Substations	Number of Feeders	Total Length of Feeders	Total Peak Load Served	Square Miles of Sub-Region
43	178	3,600 miles	1,029 MW	610

Context of the region

The Southeast sub-region includes a variety of dense areas which has resulted in a highly integrated network and also rural areas which have a more radial network. There is a high level of DERs penetration in this area relative to all other sub-regions due to the large amount of open space coupled with more robust distribution infrastructure as compared to the western area of the Commonwealth. Due to the economic development and growing suburban areas, an approximate 6.7% load growth is expected in the Southeast sub-region in the next 5 years. Additional detail can be found in Section 5.

Below are some key characteristics of the Southeast sub-region which will drive future investment needs.

Exhibit 4.70: Southeast Sub-Region Key Characteristics that will Drive Future Investment Needs

Network Characteristic	Consequence
The majority of the distribution circuits in the region are 15 kV class circuits, which operate at voltages of 13.2 kV or 13.8 kV. There are 20 circuits that operate at 4.16 kV and are supplied from substations that step down the voltage of 13 kV or 23 kV to supply customers. Lower voltages such as 4.16 kV were used more commonly in the past when loads were lower.	Areas served by these lower voltages will largely need to be converted to a higher voltage such as 13.2 kV or 13.8 kV in order to meet the significant load growth that is projected across the State. Voltage conversions can be costly and complex projects, requiring widescale replacement or upgrade of significant amounts of both distribution line and substation facilities.
The 23 kV class subtransmission circuits in the area act both as supplies to substations and to serve mostly larger load customers	Subtransmission circuits have less capacity than transmission circuits; therefore, load growth on subtransmission-supplied substations can sometimes be limited by the subtransmission feeder supplying it. As a result, the Company will need to invest in both the substation and extend transmission facilities into these areas to meet the projected load growth.

4.6.1 Maps

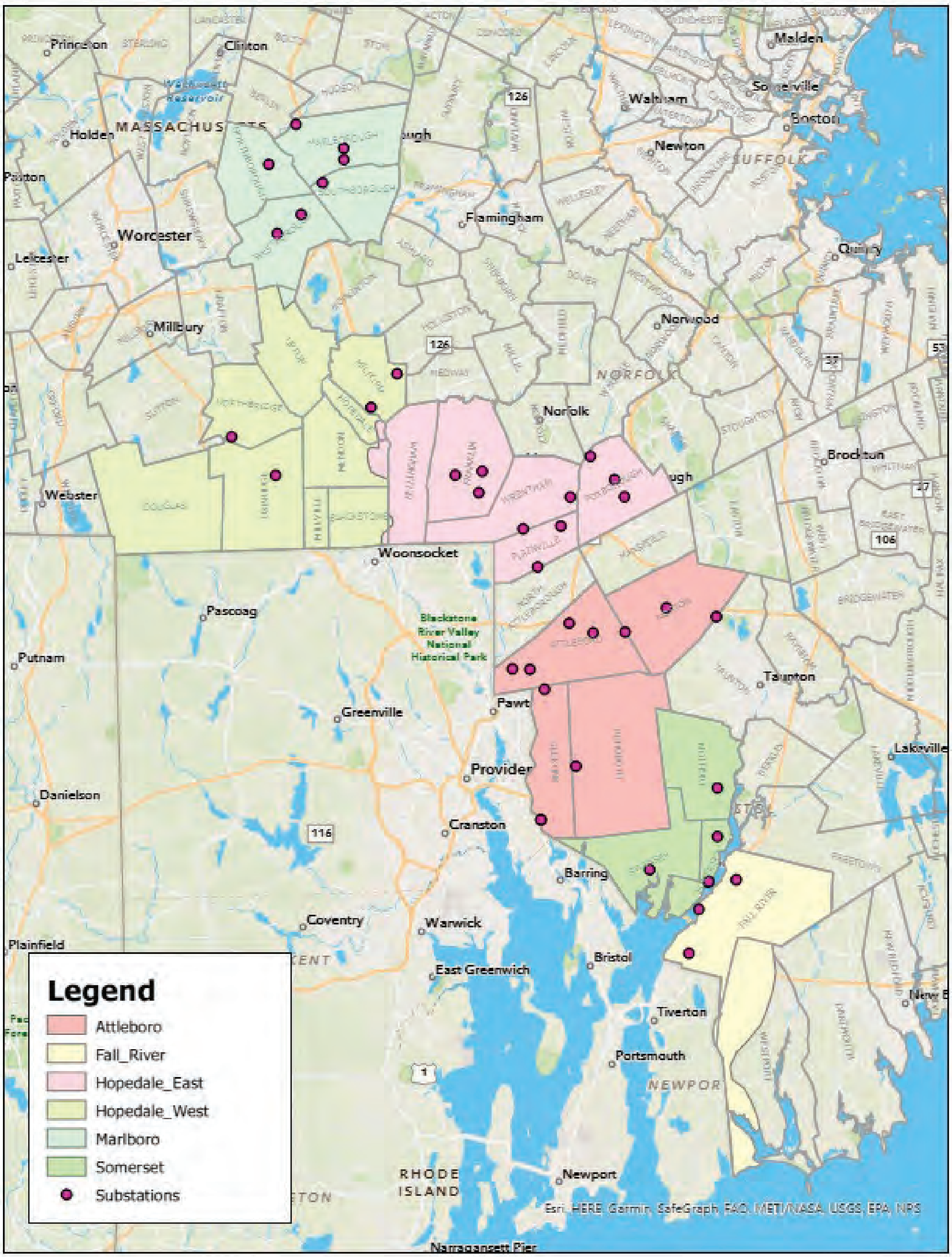
The Southeast sub-region consists of 32 towns and cities and comprises the study areas below:

Exhibit 4.71: Southeast Sub-Region Study Areas and Towns

	Study Area	Town
1	Attleboro	Attleboro, Norton, Rehoboth, Seekonk
2	Fall River	Fall River, Westport
3	Hopedale East	Bellingham, Blackstone, Foxborough, Franklin, Hopedale, Mendon, Plainville, Wrentham
4	Hopedale West	Bellingham, Blackstone, Douglas, Hopedale, Mendon, Milford, Millville, Northbridge, Upton, Uxbridge
5	Marlboro	Marlborough, Northborough, Southborough, Upton, Westborough
6	Somerset	Dighton, Somerset, Swansea

Exhibit 4.72 shows the substation locations within the Central sub-region's study areas, indicated with a red dot. Not all study areas cleanly follow town lines because they are defined electrically instead of geographically.

Exhibit 4.72: Southeast sub-region Substation Locations and Study Areas[19]



[19] Multiple substations in close proximity with one another may appear to be overlapping or as one dot on this map

4.6.2 Customer Demographics

Exhibit 4.73: Southeast sub-region customer demographics summary

Number of Customers				Residential Population Growth	Benefits of EE	Existing Connected Rooftop DER (< 25kW)
Total	Residential – Total	Residential – Low Income Rate Participants	Commercial	5-year Growth Projections		
231,799	202,218	23,996	29,581	2.2%	1,169,519 MWh	110MW

The Company serves a total of 231,799 customers (defined by individual accounts, not the number of people served) – in the Southeast sub-region. Approximately 87% (202,218) of these customers are residential customers and the other 13% are comprised of commercial, municipal, or university customers.

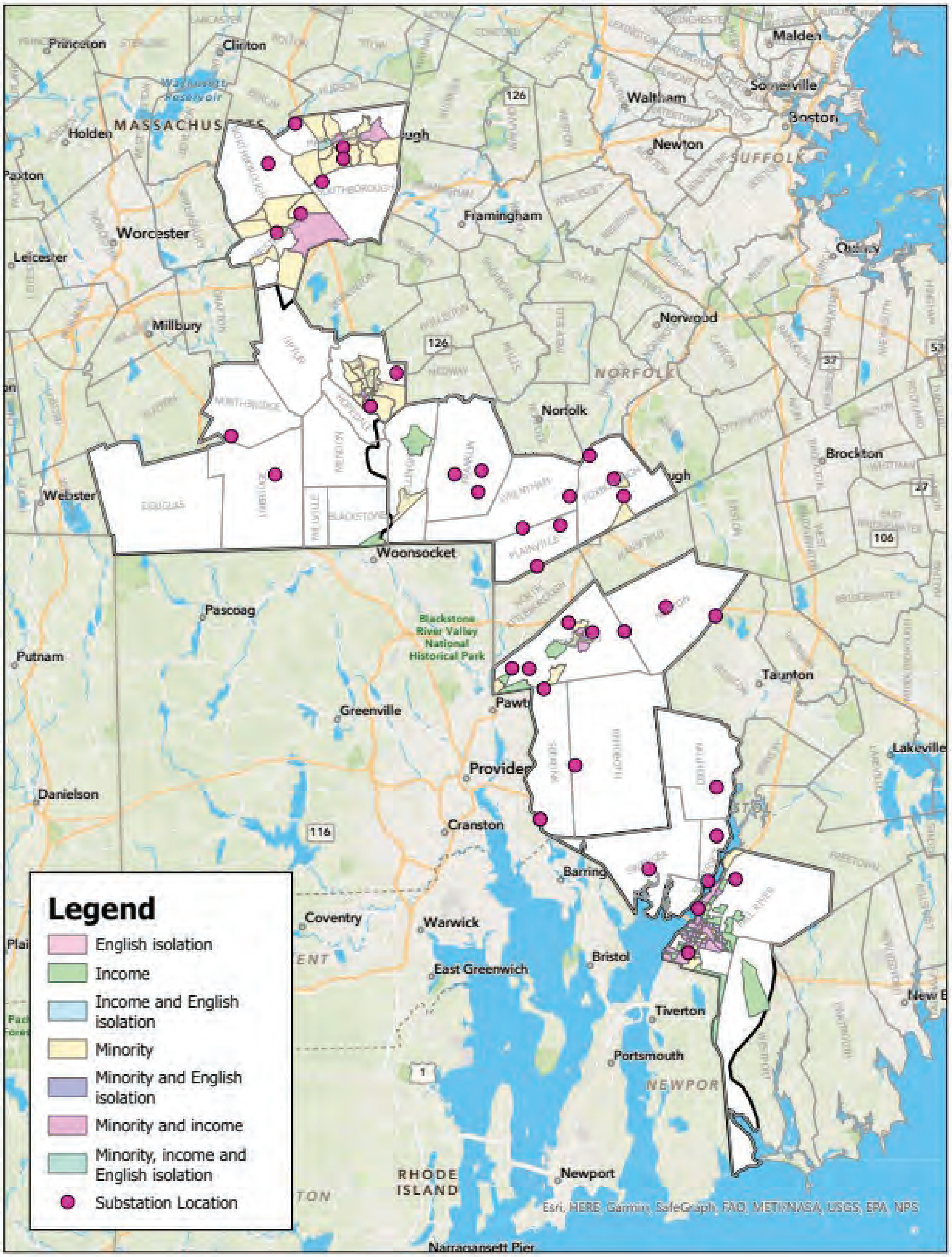
In addition to the Mass Save programs which have benefited customers in the Southeast region, 24 towns statewide have been identified for targeted outreach per the Company's MA EEAC Equity Working Group plans. Under these outreach plans the Company is specifically working to encourage more Energy Efficiency benefits in low-adoption zones. The towns/cities included in the Southeast sub-region are Attleboro and Fall River.

The Company recognizes that a significant portion of the Company's customers live in EJCs, which are disbursed throughout the Company's service area. Historically, EJCs have borne the highest energy burdens and been disproportionately impacted by the fossil-based economy. As outlined earlier in Section 3.3, the Company is developing a formal Equity and Environmental Justice Policy and Engagement Framework, as well as complementary policy and framework focused on Indigenous Peoples, which the Company will seek feedback on from those communities prior to finalizing, please refer to the Appendix for those drafts.

Exhibit 4.74 below is a map that overlays current substation locations with the Commonwealth's Environmental Justice maps, updated in 2022.[20] Exhibit 4.74 highlights concentrations of substations in many load-dense areas – town centers and other major economic areas with existing industry, or a history of industry. Load density and electric capacity needs are the key drivers to substation density and location. As the load increases, the need for more substations to serve these population centers and expanding rural areas will increase too. Many Environmental Justice Areas have been identified as such by the Commonwealth because they have been historically unduly burdened by infrastructure and related pollution. As discussed in Section 3, the Company is committed to being a trusted partner with all the Company's host communities, including those which contain Environmental Justice Populations, as new infrastructure needs to be built throughout the Commonwealth to reach decarbonization and electrification goals. Additional infrastructure that has yet to be built per recommendations in this Future Grid Plan and as part of existing investment plans can be found in Section 6.

[20] Multiple substations in close proximity with one another may appear to be overlapping or as one dot on this map

Exhibit 4.74: Southeast Sub-Region substations with the Commonwealth's EJC Map



4.6.3 Economic Development

The development of the Company's Grid Future Plan was informed, in part, by the varying levels of readiness within each sub-region. Within the Company's study areas defined in the Future Grid Plan, 14 communities have completed decarbonization plans and 139 are designated as "green communities" under M.G.L. c. 25A §10. In partnership with the Company, the following municipalities have completed a Strategic Energy Management Plan (SEMP): Athol, Beverly, Everett, Lowell, Melrose, Newburyport, and Salem. The Company anticipates one new SEMP to be signed before the end of the year, with an additional five SEMPs in the development queue.

In the Southeast sub-region, two communities (Attleboro and Westborough) have completed decarbonization plans, and 21 are designated as green communities. The region's FY23-28 CEDS focuses on workforce development, reducing unemployment, and fostering modern infrastructure investment, including utility infrastructure, to enable continued growth. The strategy is committed to exploring alternative energy sources, with an emphasis on leveraging the region's strong marine and ocean-based industries to become a hub for the off-shore wind industry.

4.6.4 Electrification Growth

Heat Electrification - The Southeast sub-region has experienced significant growth in heat pump adoption. Approximately 2,000 units have been adopted by the end of 2022, of which nearly 80% are hybrid.

Transport Electrification – There has been steady growth in the LDEV sales in the Southeast sub-region with about 5,000 vehicles as of the end of 2022. However, the MHDEVs penetration is very low at present. Since 2019, The Company has installed 390 EV charging ports via their phase I and phase II EV charging programs in the Southeast region.

4.6.5 DER Adoption (Battery Storage and Solar Photovoltaic)

With a total of 420 MW of generation connected, the Southeast sub-region has relatively high DER penetration. Connected DER is overwhelmingly solar, representing approximately 95% of the installed DER capacity.

Exhibit 4.75: Southeast sub-region DER Adoption Summary

Sub-Region	Solar (MW)	Battery (MW)	Hydro (MW)	Wind (MW)	Miscellaneous[1] (MW)	Grand Total (MW)
Southeast-Connected DER	363.3	42.0	0.1	2.0	18.3	425.6

Significant levels of DER have been connected in the Southeast sub-region, predominately in the past decade. Note that in Exhibit 4.76, the 2023 value is reflective of cumulative interconnections as of July 2023.

Exhibit 4.76: Southeast sub-region Cumulative Connected Generation and Storage

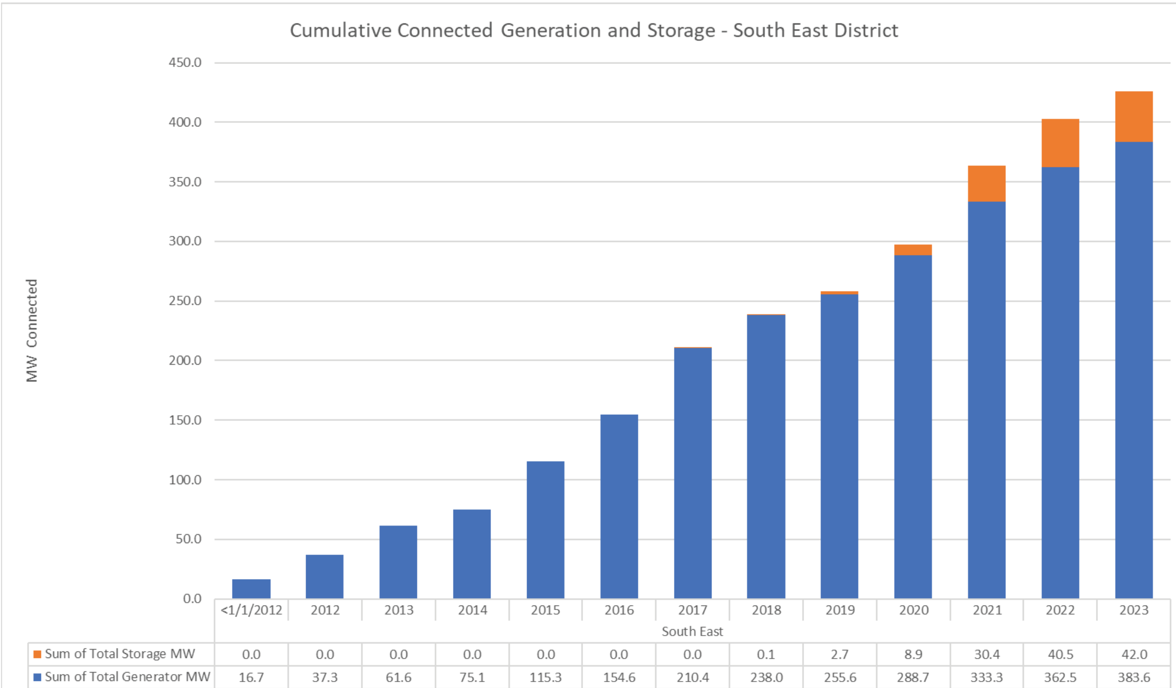


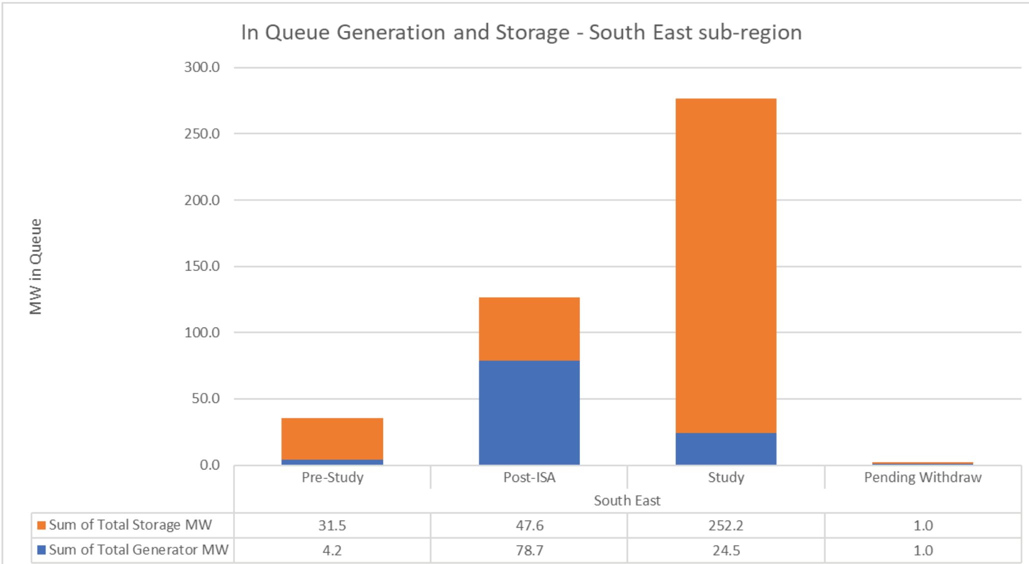
Exhibit 4.77 contains visibility of the current DER interconnection queue in the Southeast sub-region. Recent application trends have demonstrated a shift from largely solar PV applications to mainly battery storage, with batteries representing 64% of the current queued DER capacity.

A large majority of the batteries are stand-alone, albeit some are co-located as PV paired with storage. Unlike other forms of DER, which operate solely in a discharge or export capacity, contributing power to the grid, standalone batteries also must charge from the grid. While solar and other forms of DER, excluding batteries, only require there to be sufficient grid hosting capacity for their interconnection, batteries require both hosting and load-serving capacity at the location of their interconnection. Therefore, batteries are subject to capacity deficiency (i.e., charge) considerations such as those highlighted in Section 4.6.7 as well as any hosting capacity (i.e., discharge) constraints that may be present.

Exhibit 4.77: Southeast sub-region pending DER summary in queue

Sub-Region	Solar (MW)	Battery (MW)	Hydro (MW)	Wind (MW)	Miscellaneous[2] (MW)	Grand Total (MW)
Southeast – Pending DER	108.0	332.3	0.0	0.0	0.6	440.8

Exhibit 4.78: Southeast sub-region pending DER Generation and Storage in queue



Between the 440.8MW pending in queue, awaiting interconnection, and the 425.6MW already connected in the Southeast sub-region, the total for the area would be 866MW if all in-queue projects move forward. While it is unlikely that all will connect, this would be a doubling of interconnected DER in an already constrained area and would therefore require significant infrastructure expansion. Layering on the complexity of battery operation and solar variability, advanced grid management tools will be necessary in addition to the infrastructure build out to maintain the safety and reliability of the grid.

In the Southeast sub-region, the Company has analysis completed or in progress for group study for the interconnection of DER in the following study areas[3]

- Attleboro
- Fall River (North and South)
- Hopedale West
- Hopedale East

The proposed DER and system modifications required for the proposed groups have been included in the base case for the Future Grid Plan analysis; should the DER customers in these groups not proceed to interconnection, the investments described will need to be analyzed for the impacts of this attrition and adjusted appropriately. The Company is proposing to apply CIP cost allocation principles to these investments once they reach sufficient maturity.

The high-level benefits of the CIPs to distribution customers include:

- Reliability: the solution proposed to safely and reliably interconnect group study DER, in many cases coincidently, addresses existing or projected system needs. The proposed upgrades, if approved, expedite addressing these reliability concerns. These include:
  - EPS normal configuration thermal loading
  - EPS contingency configuration customer unserved
  - EPS asset conditions
- Enabled electrification: the proposed solution in some cases also provide thermal capacity beyond the planning horizon and support some loading projects out to 2050.

- Reserved Small DG: the proposed solutions also incorporate a reserved capacity on each study feeder for the small rooftops to interconnect without triggering major EPS upgrades, which typically is a direct benefit to distribution customers.

The high-level description of the common system modifications required to accommodate the interconnection of the DER included in the groups listed above are included in the Appendix. Note that these areas are in various stages of maturity and the modifications identified below are subject to change pending further analysis through the group study process. Cumulatively, in order to interconnect the 91 MW of DER proposed through the current group studies, the Company anticipates requiring system modifications that include the addition or upgrade of 7 substation transformers and approximately 30 miles of distribution line construction, at an estimated cost of $220M.

4.6.6 Grid Services (Demand Response, Smart inverter Controls, Time-varying Rates)

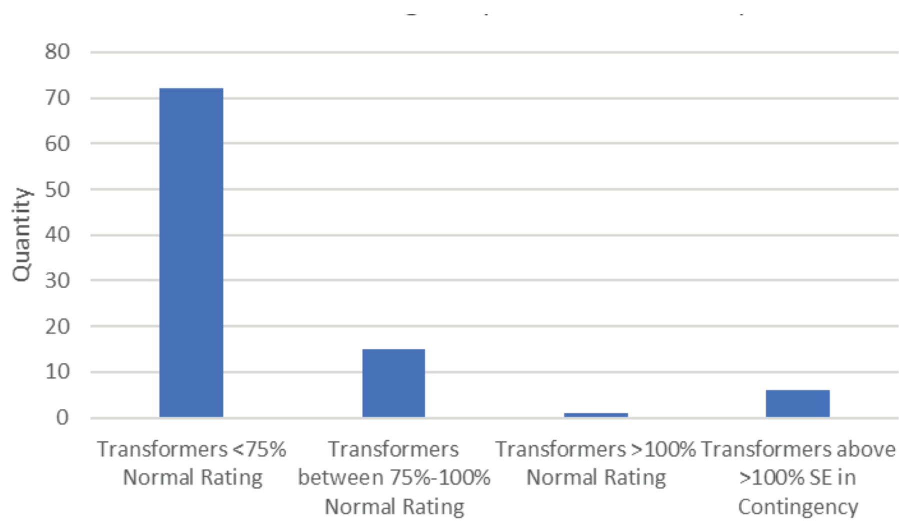
The Company currently offers several grid service participation opportunities to residential and commercial customers through its Demand Response and EV managed charging programs. Customers can earn incentives for curtailing load, pre-cooling with smart thermostats, charging their electric vehicles at optimal times, or shifting energy use with battery storage during peak load periods. As described in sections 6.3, 6.11, and 9.3 and 9.6 the Company is also on a path toward expanding grid services via AMI and time-varying rates, and leveraging DERMS technology investments to offer more dynamic, location-specific grid services as NWA solutions in the future.

In the Southeast sub-region over 8,000 customers currently participate in the Company's ConnectedSolutions DR program and help to reduce approximately 26 MW of load on the grid when the overall grid is at peak.

4.6.7 Capacity Deficiency

The exhibits below summarize the asset loading across the Southeast sub-region in 2023. The 2023 loading profile shows that most assets are loaded below 75% of their normal rating.

Exhibit 4.79: Southeast sub-region 2023 Forecasted Transformer Loading Profile

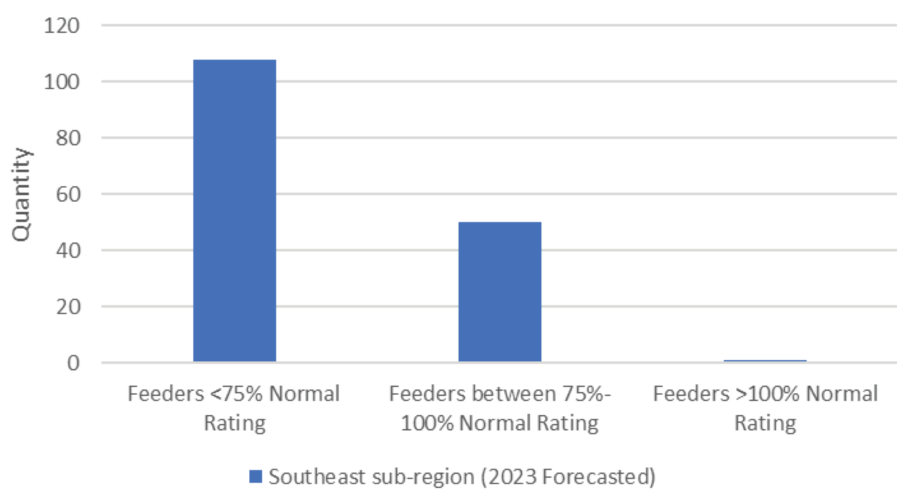


Substation transformer capacity deficiencies exist in the following areas:

Exhibit 4.80: Southeast sub-region 2023 Forecasted Transformer Capacity Deficiencies

Study Area	Substation	Capacity Deficiency
Fall River	Hathaway Substation	Transformer > 100% Normal Rating
Attleboro	Mink Street	Transformers > 100% Emergency Rating in Contingency
Hopedale East	Union Street	Transformers > 100% Emergency Rating in Contingency
Marlboro	Marlborough 311	Transformers > 100% Emergency Rating in Contingency

Exhibit 4.81: Southeast sub-region 2023 Forecasted Feeder Loading Profile



One feeder in the Southeast sub-region has an identified existing capacity deficiency. This deficiency is being monitored as an anticipated spot load comes into service, and operational mitigations will manage the overload as appropriate.

The Southeast sub-region features a 23 kV sub-transmission system known as the Union Loop which serves approximately 170 MW in the Attleboro and Hopedale East study areas. The Union Loop supplies 15 substations which step the voltage down from 23 kV to a mixture of 13 kV and 4 kV. The Union Loop has contingency loading and voltage performance concerns that limit the amount of load growth that can be supported by these substations.

Much of the Southeast sub-region shares a border with Rhode Island, and in some cases distribution facilities from one jurisdiction are supplied from the neighboring utility. In such cases, infrastructure investments in these areas must consider Rhode Island Electric as a critical stakeholder.

4.6.8 Aging Infrastructure

As energy infrastructure ages, and often consequently, its condition worsens, the risk of equipment failure increases and the reliability of operation decreases. The age of infrastructure is an important consideration when assessing the condition of assets and in efforts to meet the future demands of the network. However, the Company drives asset replacement primarily by asset condition rather than time of life. The Company's approach to maintenance has moved from a time-based approach to risk and condition based as a result of digitizing information and having real-time data. Substations and distribution lines are surveyed regularly to assess asset health and to make recommendations for replacement.

Assets are rated based on a range of criteria on their asset health, which drives asset condition replacement projects. Standard maintenance and regular testing (e.g., inspecting and replacing subcomponents of a circuit breaker) can greatly enhance reliability and extend the life of specific assets. Often, assets exceed their life expectancy if their condition and risk profile allow it, enabling the Company to maximize the value of assets while maintaining network reliability.

Additionally, as the Company moves towards modernizing and standardizing the grid and/or substations, existing equipment may need to be modified or replaced in order to digitize current methods. It is important the Company remains diligent in improving infrastructure with new technologies and remain environmentally focused. (e.g., changing substation support structure design from aluminum to steel due to efficiency and decarbonization).

Exhibit 4.82 below shows the metal clad age profile in the Southeast sub-region. Metalclads are further described in Section 4.3.8.

Exhibit 4.82: Southeast sub-region Metalclad Age Profile

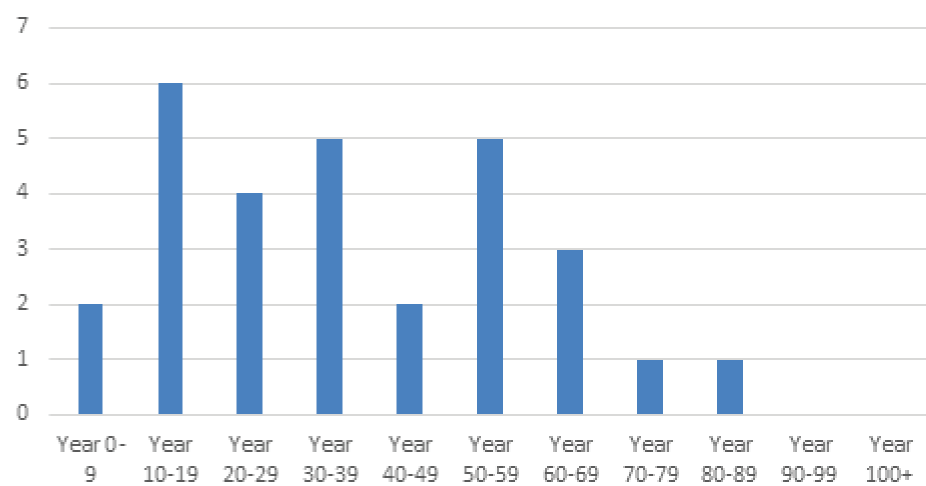


Exhibit 4.83 shows the substation transformer age profile in the Southeast sub-region.

Exhibit 4.83: Southeast sub-region Substation Transformer Age Profile

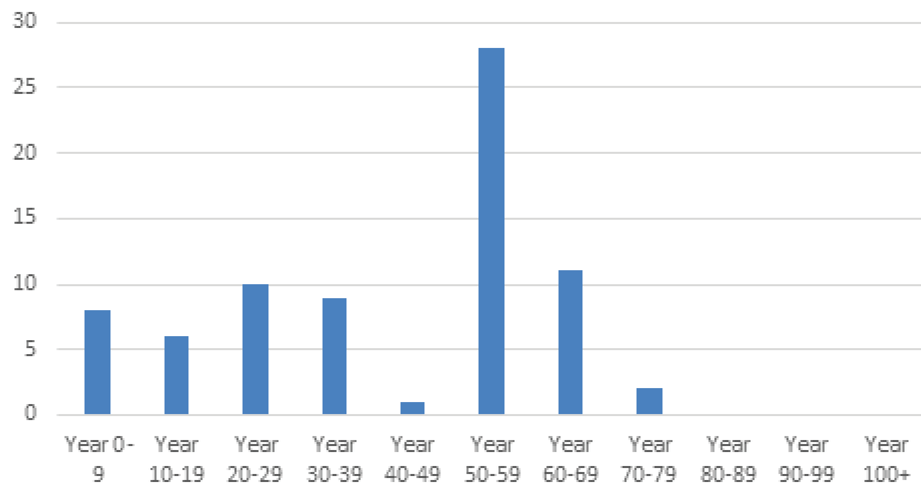


Exhibit 4.84 shows the distribution pole age profile in the Southeast sub-region.

Exhibit 4.84: Southeast sub-region Distribution Pole Age Profile

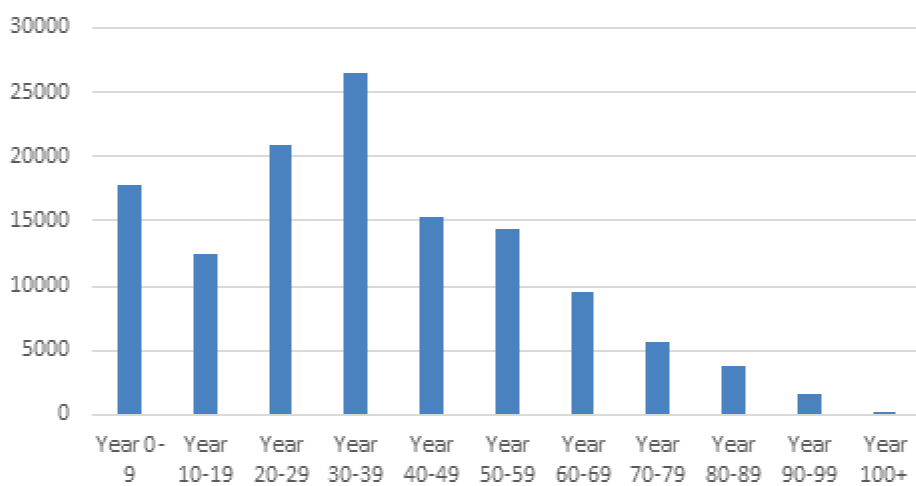
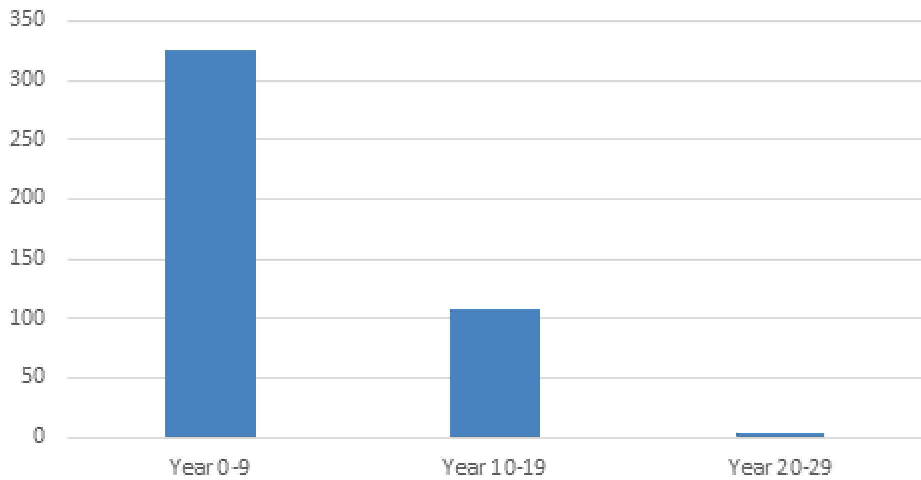


Exhibit 4.85 shows the recloser age profile in the Southeast sub-region.

Exhibit 4.85: Southeast sub-region Recloser Age Profile



4.6.9 Reliability and Resilience

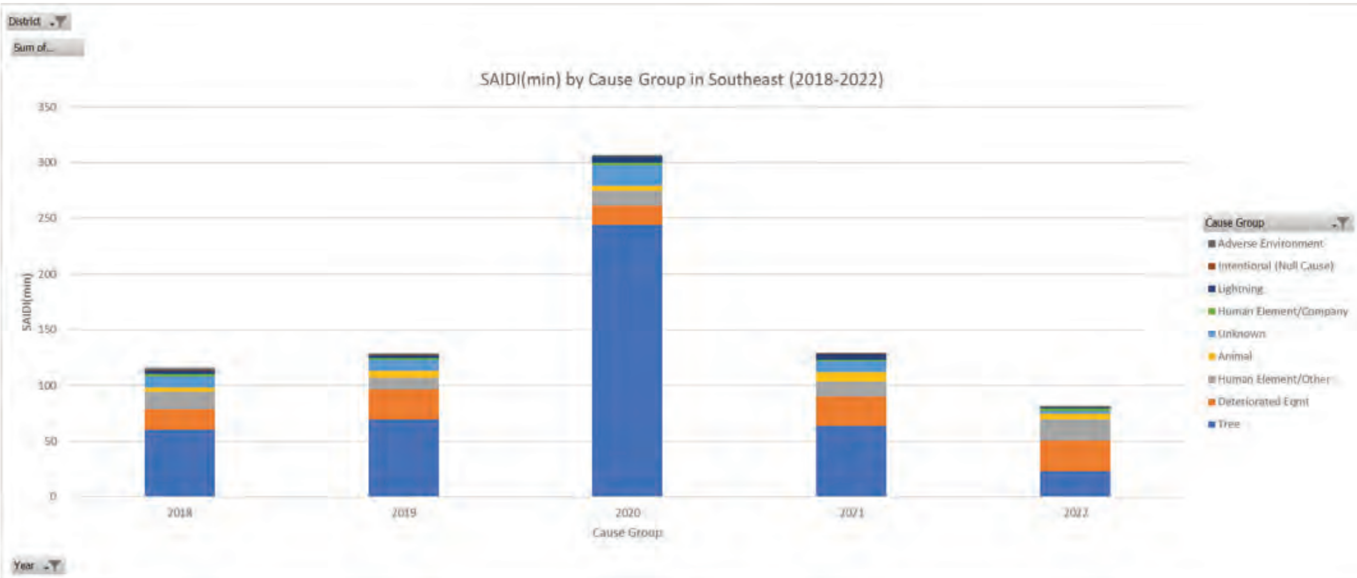
This section will describe how the Company reports reliability and what the current reliability metrics are for this given sub-region. For additional information on reliability, resiliency and company performance, the Company's annual report is here (Department Docket No. 12-120-D). This section is only illustrative for completeness of the system, and as such, relevant reliability investments are defined to be part of "core operations" and additional funding is not proposed in this Future Grid Plan. The investments proposed in the Future Grid Plan are driven by load growth and the need to increase system capacity.

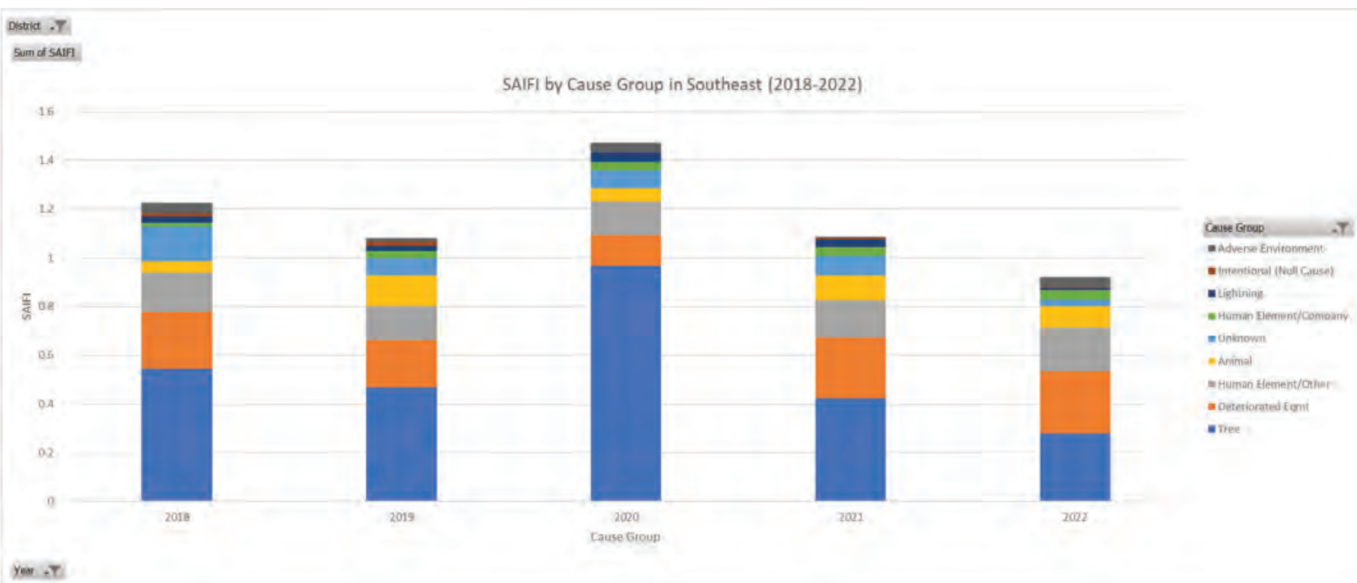
Refer to section 4.3.9 for background on reliability metrics and performance.

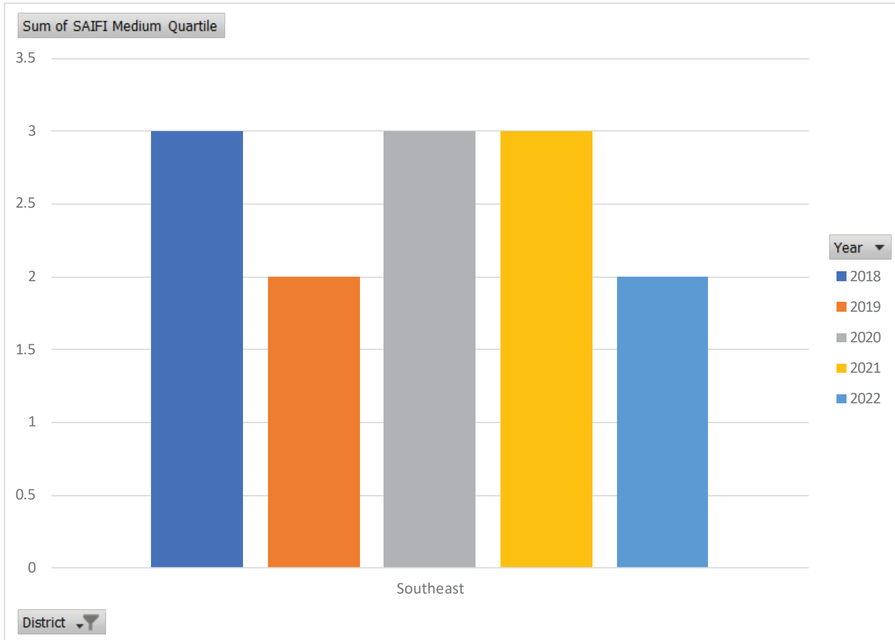
Reliability performance

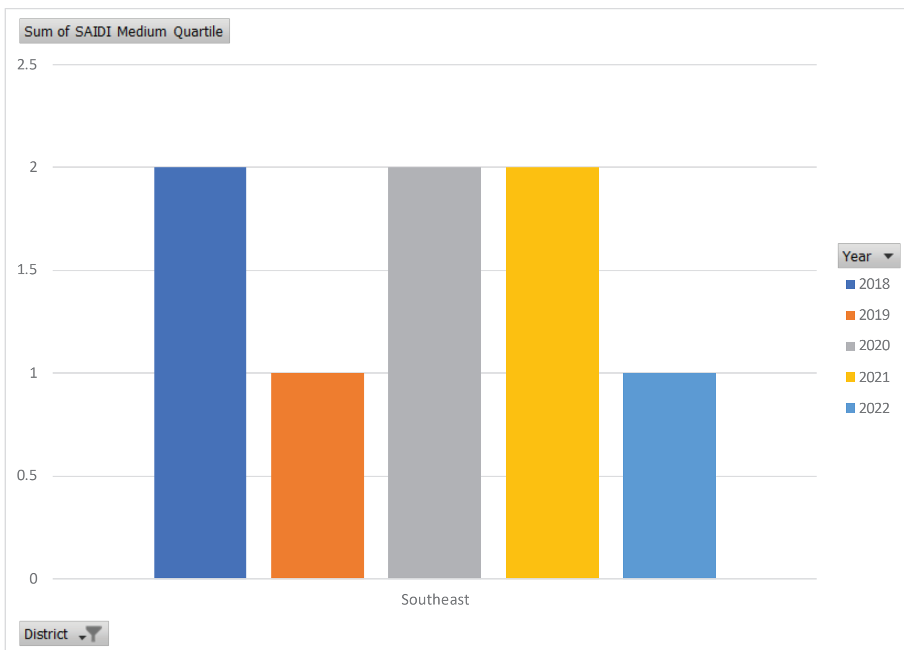
Exhibit 4.86 show the reliability performance of the sub-region in terms of duration (SAIDI) and frequency (SAIFI) of outages. The data in these Exhibits excludes major events, consistent with the Company's regulatory reporting criteria and call out leading causes of blue-sky outages for the region. Tree-related events caused most outages across this sub-region, in terms of duration and frequency.

Exhibit 4.86: Southeast sub-region Leading Causes of Blue-Sky Outages and SAIDI and SAIFI Reliability Performance









Refer to section 4.3.9 for background on how reliability metrics are calculated.

The IEEE Guide for Electric Power Distribution Reliability Indices (Standard 1366) was developed to facilitate uniformity in distribution service reliability indices and to aid in consistent reporting practices related to distribution systems, substations, circuits, and defined regions. While this methodology differs from the criteria applied to the Company's regulatory reliability reporting obligations, this approach was utilized to demonstrate the performance of the Company's distinct sub-regions as compared to similar size utilities responding to the survey (>100,000 - <1,000,000 customers). The benchmarking analysis showed that for two out of the last four years, the Southeast has been in the second quartile for frequency of outages (SAIFI) and has been in the first or second quartile for the past five years for duration (SAIDI).

Resiliency performance

As described in section 4.3.9, outage impacts from major events are traditionally excluded from reliability reporting, as described above. The Company calculated "all-in" SAIDI and SAIFI indices across its service territory to facilitate comparison of the resiliency and reliability challenges experienced in each sub-region relative to the others. This comparison highlights areas where emerging resiliency challenges have been experienced in the past five years. The methodologies that went into these calculations are described in section 4.3.9. Substations may have no reliability data for several reasons, including no recorded events over the time period or if they do not directly serve load to customers.

The following maps illustrate the substation resiliency of this sub-region overlaid with EJCs, as defined by the Commonwealth. The exhibits below show the Company's distribution substation locations within the Southeast sub-region overlaid with EJCs. Each distribution substation is color-coded indicating its five-year historical SAIDI or SAIFI performance relative to the Company's entire population of substations. A greater density of distribution substations typically results in shorter distribution feeders with less outage exposure and increased numbers of feeder ties, resulting in better overall reliability. As can be seen in each of these Exhibits, substations in the EJCs fall within the top first and second quartile of SAIDI and SAIFI performance relative to the entire population of the Company's distribution substations.

Exhibit 4.87: Southeast sub-region Resiliency in EJCs as shown as SAIDI Substation Performance

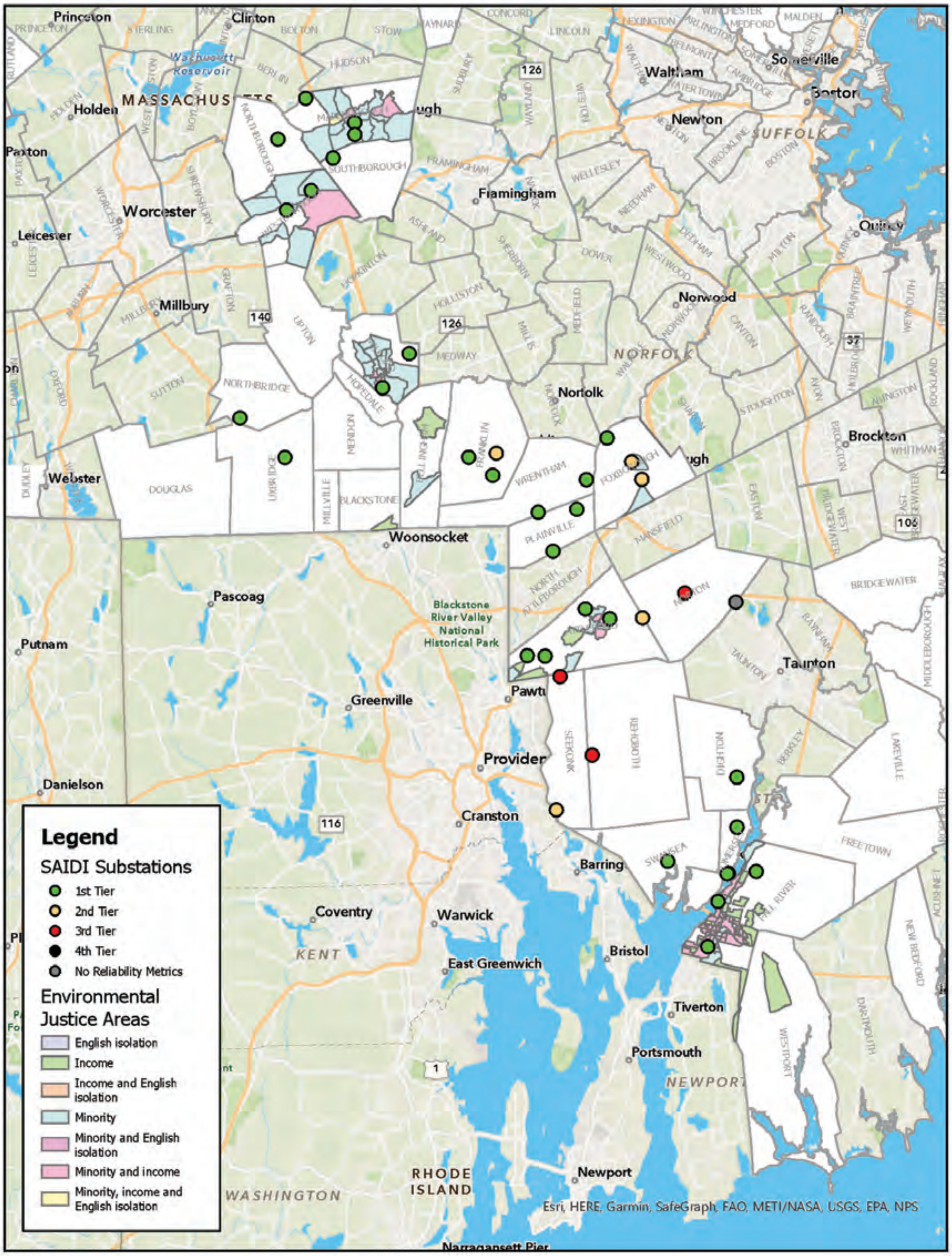
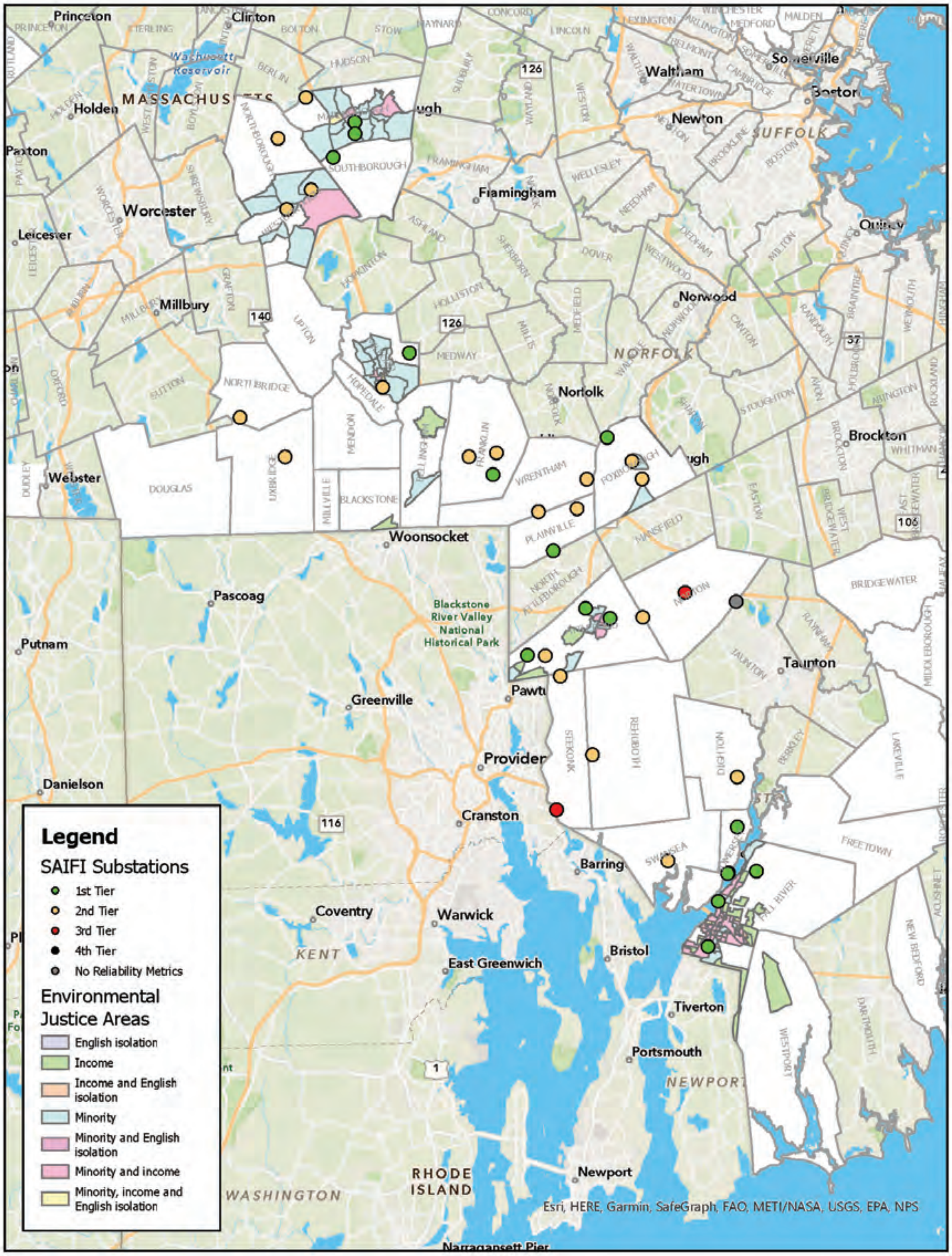


Exhibit 4.88: Southeast sub-region Resiliency in EJCs as shown as SAIFI Substation Performance



When looking at the 5-year performance, 2020 was particularly a bad year as the Company experienced 18 storm events that were not classified as major events. The impact of each event added together reflects the bad reliability performance at the system level. Also worth noting was that 2018 and 2021 were bad years of performance for the eastern part of the Company's Commonwealth service territory given three back-to-back storms occurring in early 2018 and a Nor'easter occurring in October 2021. As a result, substations in the fourth quartile of SAIDI/SAIFI performance can be seen in South Shore, Southeast and Merrimack Valley region maps.

4.6.10 Siting and Permitting

Energy infrastructure siting and permitting processes are generally consistent across the Commonwealth; therefore, siting and permitting challenges do not vary significantly by region. When projects require considerable underground transmission work, the EFSB review process is triggered to ensure the work is in compliance with State requirements. This EFSB review process is intended to take twelve months (see G.L. c. 164, Section 69J); however, the review timeline for recently submitted transmission line projects is trending toward 30 to 36 months.

Environmentally, the largest differences are at a municipal level rather than regionally. At the project-level, Conservation Commission impacts uniformly across the State but there is a high degree of variability town to town and year to year, which makes it challenging to generalize regionally.

Since the Southeast sub-region is one of the more developed regions, the Company has faced increased challenges in identifying suitable locations for energy infrastructure. Each site presents different siting and environmental considerations, especially given the wetland mitigation requirements for permanently impacted land.

4.7 South Shore Sub-Region

The South Shore sub-region in brief:

Nature of the area: The South Shore sub-region is predominantly suburban, with regional urban centers in Brockton and Quincy.

The Company's customers' energy needs, economic circumstances and demographics in the South Shore sub-region vary, which is why targeted, and culturally competent community engagement is at the core of the Company's plan to help the State achieve its goals.

Exhibit 4.89: South Shore sub-region customers by the numbers

Total Customers (accounts)	% Residential	%Business, Commercial, Municipal, or University	Benefits of EE	Heat Pump Adoption (end of 2022)	Total NG Charging Ports Installed
239,140	88%	12%	1,206,558 MWh	1,470	244 Ports

Exhibit 4.90: South Shore sub-region network by the numbers

Number of Substations	Number of Feeders	Total Length of Feeders	Total Peak Load Served	Square Miles of Region
39	187	2,932 miles	938 MW	404

Context of the region

The South Shore sub-region includes several dense urban areas which have a highly integrated network and also some more sparse suburban areas which have a more radial network. The South Shore sub-region has moderate levels of DERs penetration relative to all other sub-regions due to the somewhat limited amount of open space coupled with limited capacity on the distribution system. Due to the growing suburban areas, an approximate 6.5% load growth is expected in the South Shore region in the next 5 years. Additional details can be found in Section 5.

Below are some key characteristics of the South Shore sub-region which will drive future investment needs.

Exhibit 4.91: South Shore Sub-Region Key Characteristics that will Drive Future Investment Needs

Network Characteristic	Consequence
Legacy planning and construction practices in the South Shore sub-region led to a high proportion of substations with a single transformer, relying mainly on distribution feeder ties to transfer customers to neighboring substations in the event of a transformer outage. As load has grown in the region these practices have not been sustainable.	To accommodate load growth and continue to provide reliable service to customers, the Company needs to add second transformers at substations throughout the region, many of which were not originally designed to accommodate a second transformer or transmission supply.
Nantucket is a geographical and electrical island supplied by two undersea subtransmission cables which limit the load growth on the island.	Load growth on the Island will require us to establish additional undersea supply cables, which are high cost and high complexity projects.

4.7.1 Maps

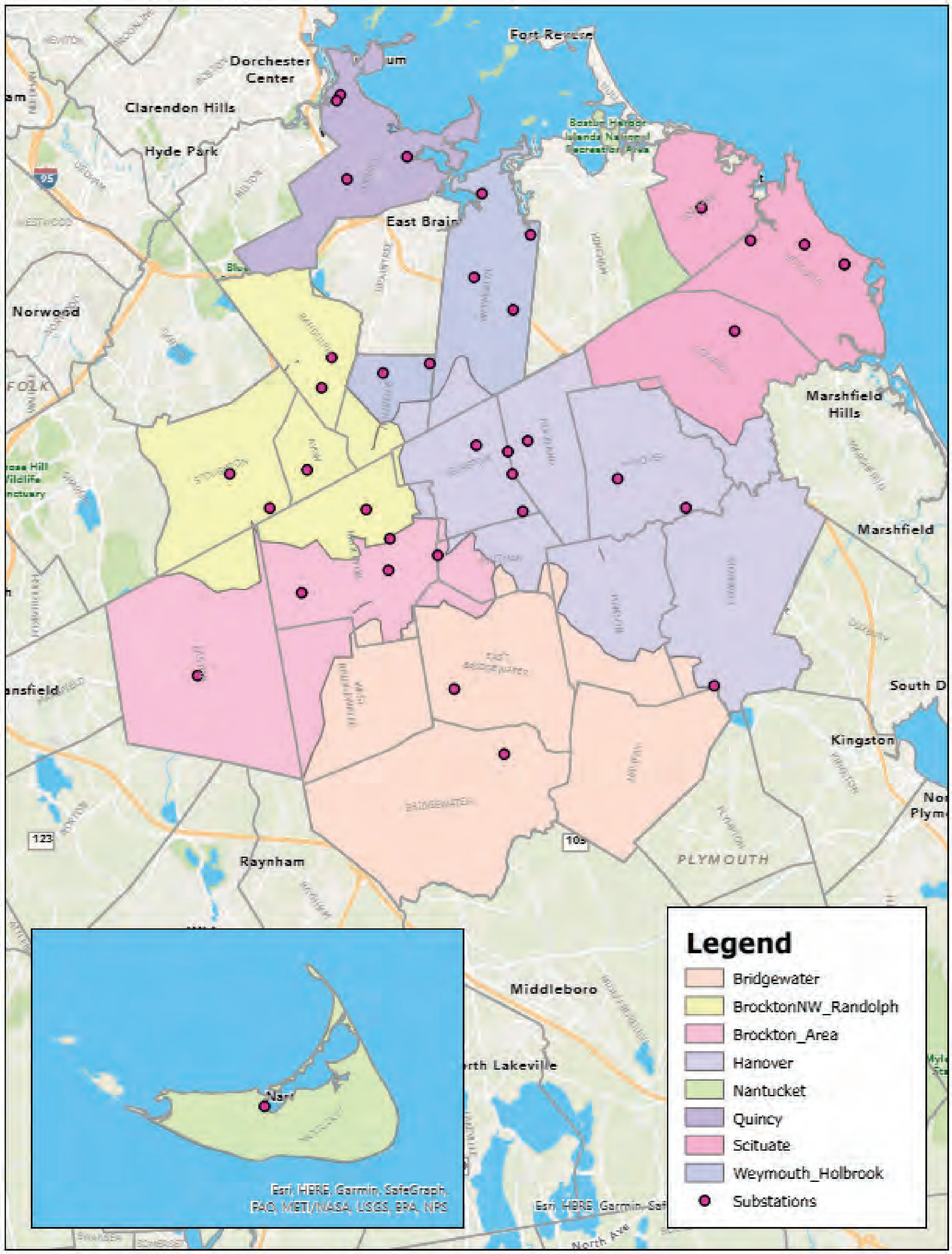
The South Shore sub-region consists of 21 towns and cities and comprises the study areas below:

Exhibit 4.92: South Shore Sub-Region Study Areas and Towns

	Study Area	Town
1	Bridgewater	Bridgewater, Brockton, East Bridgewater, Halifax, Hanson, Pembroke, West Bridgewater, Whitman
2	Brockton	Abington, Brockton, East Bridgewater, Easton, West Bridgewater, Whitman
3	Brockton NW/ Randolph	Abington, Avon, Brockton, Easton, Holbrook, Randolph, Stoughton
4	Hanover	Abington, Brockton, Hanover, Hanson, Holbrook, Norwell, Pembroke, Rockland, Weymouth, Whitman
5	Nantucket	Nantucket
6	Quincy	Quincy
7	Scituate	Cohasset, Hanover, Norwell, Scituate
8	Weymouth/Holbrook	Holbrook, Weymouth

Exhibit 4.93 shows the substation locations within the South Shore sub-region's study areas, indicated with a red dot. Not all study areas cleanly follow town lines because they are defined electrically instead of geographically.

Exhibit 4.93: South Shore sub-region Substation Locations and Study Areas



4.7.2 Customer Demographics

Exhibit 4.94: South Shore sub-region customer demographics summary

Number of Customers				Residential Population Growth	Benefits of EE	Existing Connected Rooftop DER (< 25kW)
Total	Residential – Total	Residential – Low Income Rate Participants	Commercial	5-year Growth Projections		
239,140	210,181	25,105	28,959	2.2%	1,206,558 MWh	90MW

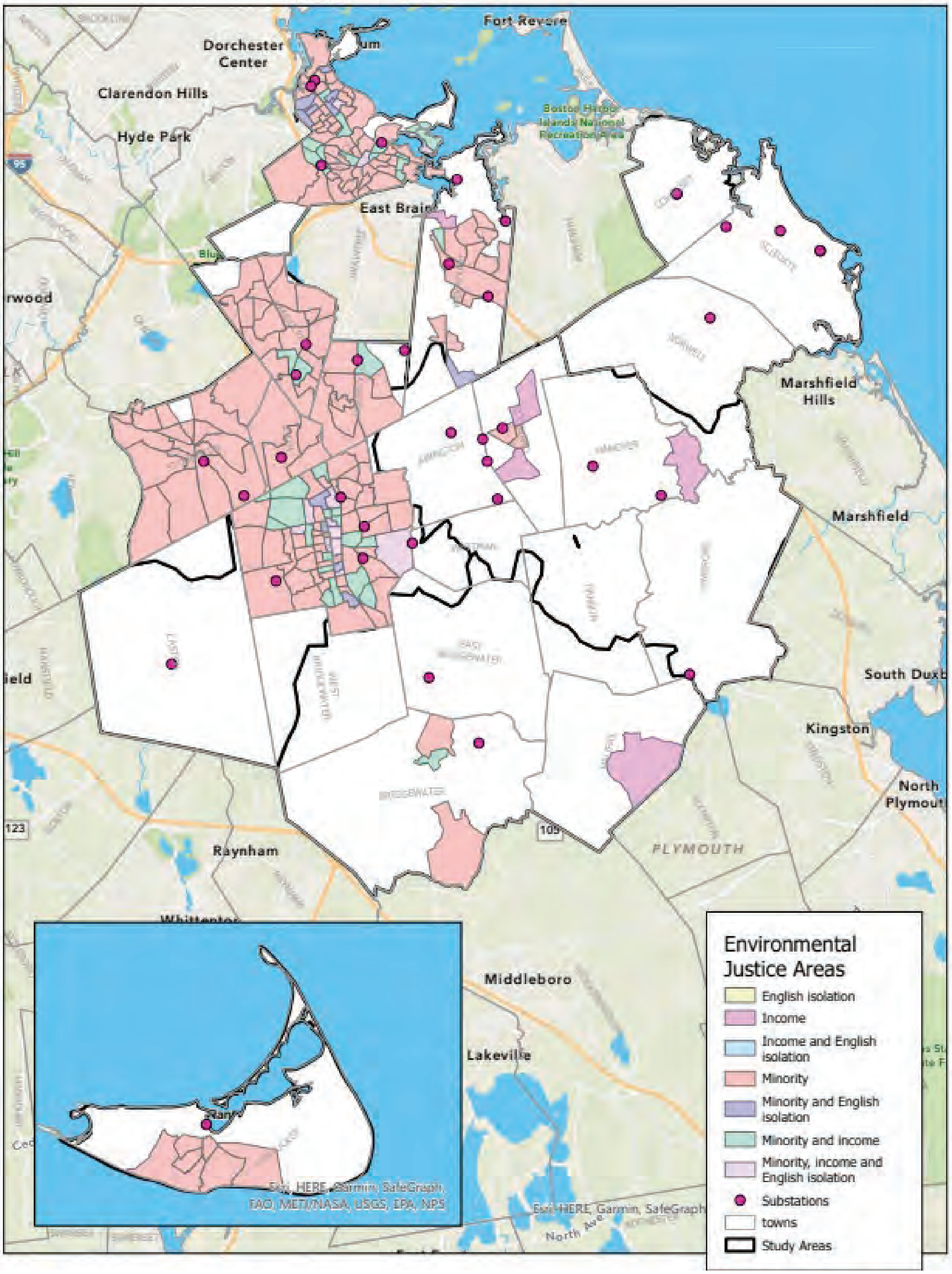
The Company serves a total of 239,140 customers (defined by individual accounts, not the number of people served) – in the South Shore sub-region. Approximately 88% (210,181) of these customers are residential customers and the other 12% are comprised of commercial, municipal, or university customers.

In addition to the Mass Save programs which have benefited customers in the central region, the Company has 24 towns statewide identified for targeted outreach per the MA EEAC Equity Working Group plans. Under these outreach plans the Company is specifically working to encourage more Energy Efficiency benefits in low-adoption zones. The towns/cities included in the South Shore region are Brockton, Stoughton, Holbrook, Randolph, and Quincy.

The Company recognizes that a significant portion of the Company's customers live in EJCs, which are disbursed throughout the Company's service area. Historically, EJCs have borne the highest energy burdens and been disproportionately impacted by the fossil-based economy. As outlined earlier in Section 3.3, the Company is developing a formal Equity and Environmental Justice Policy and Engagement Framework, as well as complementary policy and framework focused on Indigenous Peoples, which the Company will seek feedback on from those communities prior to finalizing, please refer to the Appendix for those drafts.

Exhibit 4.95 is a map that overlays current substation locations with the Commonwealth's Environmental Justice maps, updated in 2022. Exhibit 4.95 highlights concentrations of substations in many load-dense areas – town centers and other major economic areas with existing industry, or a history of industry. Load density and electric capacity needs are the key drivers to substation density and location. As the load increases, the need for more substations to serve these population centers and expanding rural areas will increase as well. Many EJCs have been identified as such by the Commonwealth because they have been historically unduly burdened by infrastructure and related pollution. As discussed in Section 3, the Company is committed to being a trusted partner with all the Company's host communities, including those which contain EJCs, as new infrastructure needs to be built throughout the Commonwealth to reach decarbonization and electrification goals. Additional infrastructure that has yet to be built per recommendations in the Future Grid Plan and as part of existing investment plans can be found in Section 6.

Exhibit 4.95: South Shore sub-region substations with the Commonwealth's EJC map



4.7.3 Economic Development

The development of the Company's Grid Future Plan was informed, in part, by the varying levels of readiness within each sub-region. Within the Company's study areas defined in the Future Grid Plan, 14 communities have completed decarbonization plans and 139 are designated as "green communities" under M.G.L. c. 25A §10. In partnership with the Company, the following municipalities have completed a Strategic Energy Management Plan (SEMP): Athol, Beverly, Everett, Lowell, Melrose, Newburyport, and Salem. The Company anticipates one new SEMP to be signed before the end of the year, with an additional five SEMPs in the development queue.

In the South Shore sub-region, 20 communities are designated as green communities. In recent years, the region has focused on fostering smart grown and sustainable development, ensuring adequate infrastructure to support economic development, and promoting regional economic self-sufficiency and resilience. Included in the most recent regional CEDS are goals to expand and revitalize commercial land, reuse urban facilities, and support transportation-oriented development to foster economic development and bolster tourism.

4.7.4 Electrification Growth

Heat Electrification - The South Shore sub-region has moderate pump adoption compared to the other five sub-regions. About 1,000 units have been adopted by the end of 2022, of which over 60% are hybrid.

Transportation Electrification – There has been steady growth in LDEV sales in the South Shore sub-region with about 5,000 vehicles as of the end of 2022. However, the total number of MHDEVs is less than 5 indicating very low penetration at present. Since 2019, the Company has installed 244 EV charging ports via their phase I and phase II electric vehicle charging programs in the South Shore region.

4.7.5 DER Adoption (Battery Storage and Solar Photovoltaic)

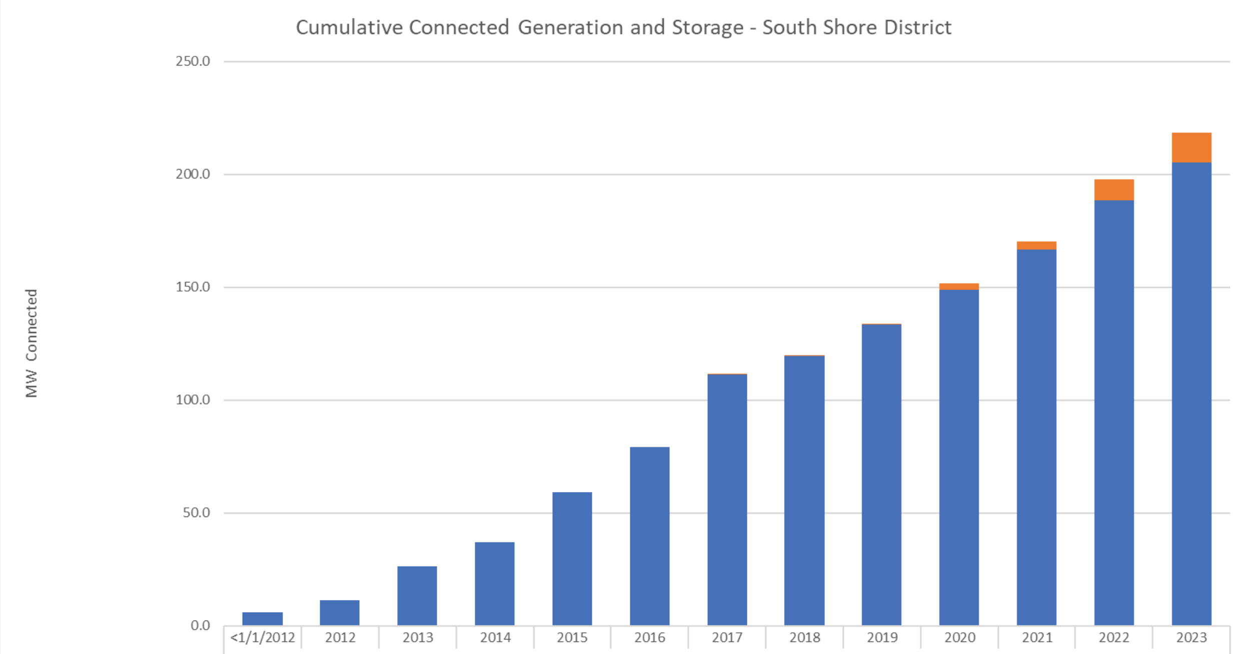
With a total of 215.6 MW of generation connected, the South Shore sub-region has a moderate DER penetration. Connected DER is predominately solar, representing 94% of the installed DER capacity in the sub-region.

Exhibit 4.96: South Shore sub-region DER adoption summary

Sub-Region	Solar (MW)	Battery (MW)	Hydro (MW)	Wind (MW)	Miscellaneous [1] (MW)	Grand Total (MW)
South Shore – Connected DER	193.7	13.5	0.0	2.4	7.5	218.6

Significant levels of DER have been connected in the South Shore sub-region, predominately in the past decade. Note that in Exhibit 4.97 below the 2023 value is reflective of year-to-date interconnections as of July 2023. Exhibit 4.97 below shows the cumulative connected DER in the South Shore sub-region.

Exhibit 4.97: South Shore sub-region Cumulative Connected Generation and Storage



	<1/1/2012	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Sum of Total Storage MW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.4	2.7	3.7	9.3	13.5
Sum of Total Generator MW	5.9	11.5	26.5	37.2	59.3	79.2	111.2	119.6	133.3	148.9	166.6	188.3	205.0

Exhibit 98 below contains visibility of the current DER interconnection queue in the South Shore sub-region. Recent application trends have demonstrated a shift from largely solar PV applications to mainly battery storage, with batteries representing 72% of the current queued DER capacity.

A large majority of the batteries are stand-alone, albeit some are co-located as PV paired with storage. Unlike other forms of DER, which operate solely in a discharge or export capacity, contributing power to the grid, standalone batteries also must charge from the grid. While solar and other forms of DER, excluding batteries, only require there to be sufficient grid *hosting* capacity for their interconnection, batteries require both hosting and load-serving capacity at the location of their interconnection. Therefore, batteries are subject to capacity deficiency (i.e., charge) considerations such as those highlighted in Section 4.7.7 as well as any hosting capacity (i.e., discharge) constraints that may be present.

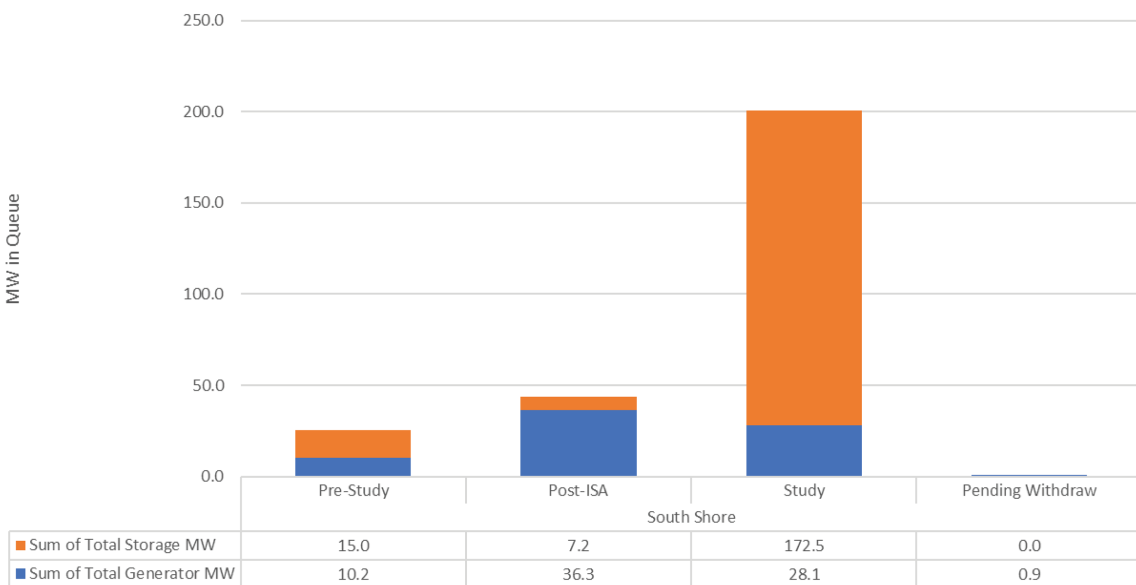
This significantly increases the complexity of planning and operating the network.

Exhibit 4.98: South Shore sub-region pending DER summary in queue

Sub-Region	Solar (MW)	Battery (MW)	Hydro (MW)	Wind (MW)	Miscellaneous[2] (MW)	Grand Total (MW)
South Shore – Pending DER	60.4	194.8	0.0	0.0	0.3	255.4

Exhibit 4.99 below shows the cumulative queue DER in the South Shore sub-region.

Exhibit 4.99: South Shore sub-region pending DER Generation and Storage in queue



Combining the 255.4MW in the interconnection queue, and the 218.6MW already connected in the South Shore sub-region, the total for the area would be 474MW if all in-queue projects move forward. While it is unlikely that all will connect, this would be a doubling of interconnected DER in an already constrained area and would therefore require significant infrastructure expansion.

In the South Shore sub-region, the Company has analysis completed or in progress for group study for the interconnection of DER in the following study areas[3]:

- Brockton (North and South)
- Bridgewater
- Hanover
- Scituate

The proposed DER and system modifications required for the proposed groups have been included in the base case for the Future Grid Plan analysis; should the DER customers in these groups not proceed to interconnection the investments described in will need to be analyzed for the impacts of this attrition and adjusted appropriately. The Company is proposing to apply CIP cost allocation principles to these investments once they reach sufficient maturity.

The high-level benefits of the CIPs to distribution customers include:

- Reliability: the solution proposed to safely and reliably interconnect group study DER, in many cases coincidently, addresses existing or projected system needs. The proposed upgrades, if approved, expedite addressing these reliability concerns. These include:
  - EPS normal configuration thermal loading
  - EPS contingency configuration customer unserved
  - EPS asset conditions
- Enabled electrification: the proposed solution in some cases also provide thermal capacity beyond the planning horizon and support some loading projects out to 2050.

- Reserved Small DG: the proposed solutions also incorporate a reserved capacity on each study feeder for the small rooftops to interconnect without triggering major EPS upgrades, which typically is a direct benefit to distribution customers.

The high-level description of the common system modifications required to accommodate the interconnection of the DER included in the groups listed above are included in the Appendix. Note that these areas are in various stages of maturity and the modifications identified below are subject to change pending further analysis through the group study process. Cumulatively, in order to interconnect the 86 MW of DER proposed through the current group studies, the Company anticipates requiring system modifications that include the addition or upgrade of 3 substation transformers and approximately 17 miles of distribution line construction, at an estimated cost of $168M.

4.7.6 Grid Services (Demand Response, Smart inverter Controls, Time-varying Rates)

The Company currently offers several grid service participation opportunities to residential and commercial customers through its Demand Response and EV managed charging programs. Customers can earn incentives for curtailing load, pre-cooling with smart thermostats, charging their electric vehicles at optimal times, or shifting energy use with battery storage during peak load periods. As described in sections 6.3, 6.11, and 9.3 and 9.6 the Company is also on a path toward expanding grid services via AMI and time-varying rates, and leveraging DERMS technology investments to offer more dynamic, location-specific grid services as NWA solutions in the future.

In the South Shore region over 7,000 customers currently participate in ConnectedSolutions DR program and help to reduce approximately 18 MW of load on the grid when the overall grid is at peak.

4.7.7 Capacity Deficiency

The graphs below summarize the asset loading across the South Shore and Nantucket sub-regions in 2023. The 2023 loading profile shows that most assets are loaded below 75% of their normal rating.

Exhibit 4.100 displays the 2023 forecasted transformer loading in the South Shore sub-region.

Exhibit 4.100: South Shore sub-region 2023 Forecasted Transformer Loading Profile

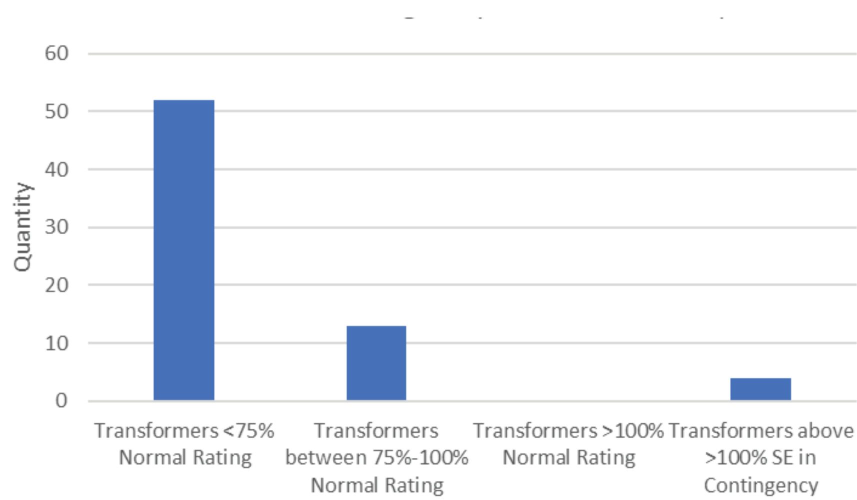
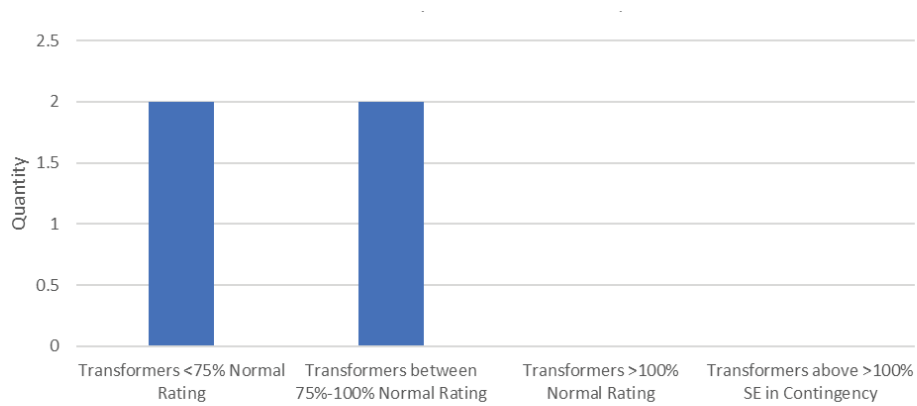


Exhibit 4.101 below displays the 2023 forecasted transformer loading in Nantucket.

Exhibit 4.101: 2023 Forecasted Transformer Loading Profile – Nantucket



Substation transformer capacity deficiencies exist in the following areas:

Exhibit 4.102: South Shore sub-region 2023 Forecasted Transformer Capacity Deficiencies

Study Area	Substation	Capacity Deficiency
Bridgewater	East Bridgewater	Transformer > 100% Normal Rating
Brockton NW /Randolph	South Randolph 97	Transformers > 100% Emergency Rating in Contingency
Brockton	Dupont 91	Transformers > 100% Emergency Rating in Contingency

Exhibit 4.103: South Shore sub-region 2023 Forecasted Feeder Loading Profile

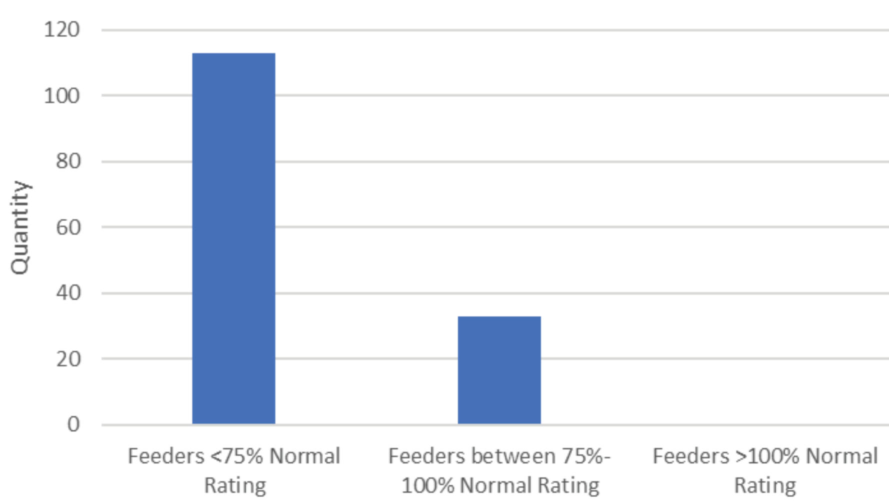
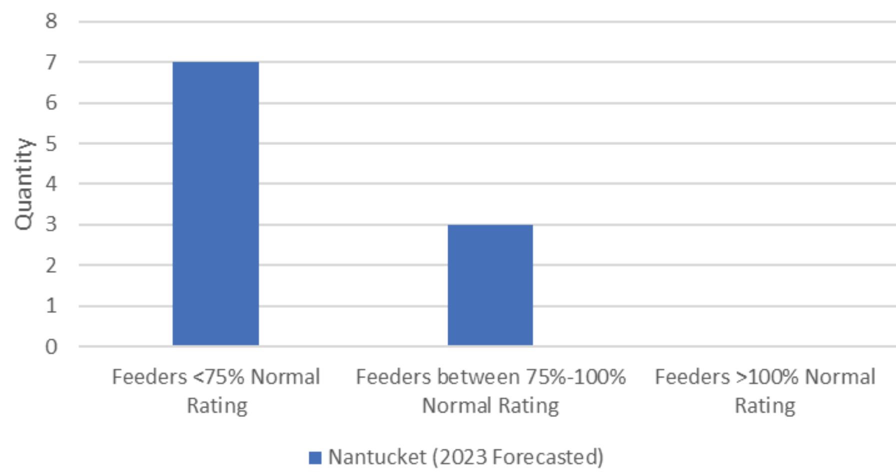


Exhibit 4.104: South Shore sub-region 2023 Forecasted Feeder Loading Profile - Nantucket



The South Shore sub-region has two large urban areas of Quincy and Brockton that are experiencing large load growth. Space within these areas is limited, and parcels of land to add and/or upgrade existing infrastructure will prove difficult to accommodate the load growth. Other portions of the South Shore are more suburban and rural with longer distribution circuits, which makes voltage regulation and reliability more difficult to achieve.

There is also a lack of transmission infrastructure in the region. Larger capacity transmission lines, like that of115 kV supply cables, will need to be extended and/or built in order to serve more areas to accommodate the expected load growth.

The island of Nantucket poses a challenge. The island is currently supplied by only two 46 kV submarine cables from Lothrop Ave and Merchants Way substations from Cape Cod. These cables are reaching their maximum capacity limit and more supply will need to be brought over to the island in the near future. Cost estimates for submarine cables are exceptionally high, making the island both a technical and financial challenge to keep up with the expected load growth.

4.7.8 Aging Infrastructure

This section is only illustrative for completeness of the system, and as such, relevant aging infrastructure investments are defined to be part of “core operations” and additional funding is not proposed in this plan. The investments proposed in this Future Grid Plan are driven by load growth and the need to increase system capacity.

As energy infrastructure ages, and often consequently, its condition worsens, the risk of equipment failure increases and the reliability of operation decreases. The age of infrastructure is an important consideration when assessing the condition of assets and in efforts to meet the future demands of customers and the network. However, asset replacement is driven primarily by asset condition rather than time of life. The Company’s approach to maintenance has moved from a time-based approach to risk and condition based as a result of digitizing information and having real-time data. Substations and distribution lines are surveyed regularly to assess asset health and to make recommendations for replacement.

Assets are rated based on a range of criteria to assess their health, which drives asset condition replacement projects. Standard maintenance and regular testing (e.g., inspecting and replacing subcomponents of a circuit breaker) can enhance reliability and extend the life of specific assets. Often, assets exceed their life expectancy if their condition and risk profile allow it, enabling the Company to maximize the value of assets while maintaining network reliability.

Additionally, as the Company moves towards modernizing and standardizing the grid and/or substations, existing equipment may need to be modified or replaced in order to digitize current methods. It is important the Company remains diligent in improving their infrastructure with new technologies and remains environmentally focused. (e.g., changing substation support structure design from aluminum to steel due to efficiency and decarbonization).

Exhibit 105 shows the metalclads age profile in the South Shore sub-region.

Exhibit 4.105: The Metalclad Age Profile – South Shore Sub-Region

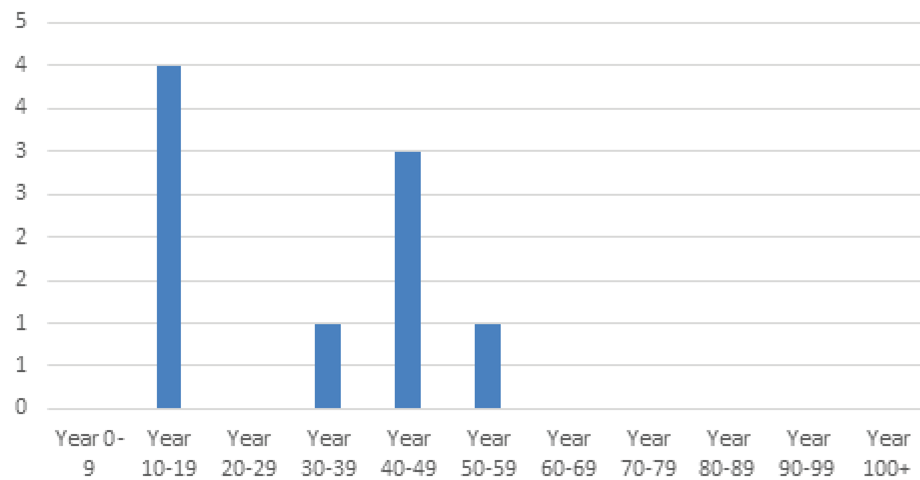


Exhibit 106 shows the transformers age profile in the South Shore sub-region.

Exhibit 4.106: South Shore sub-region Substation Transformer Age Profile

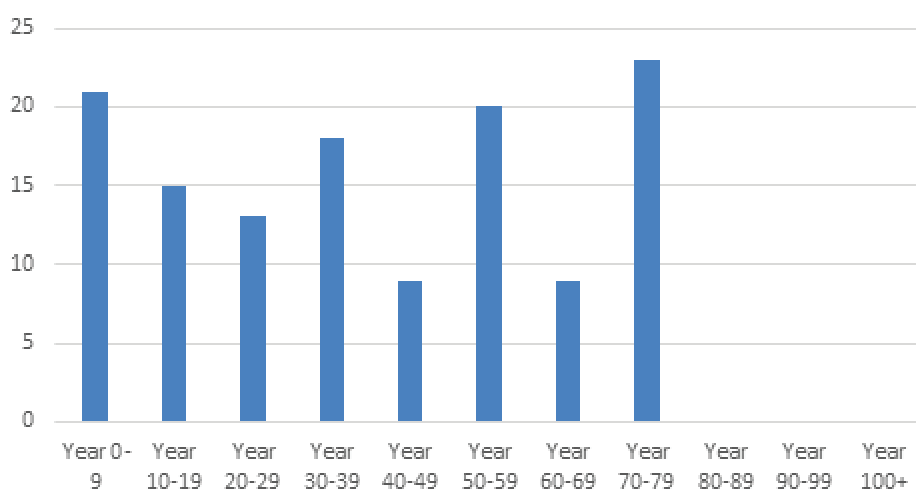


Exhibit 107 shows the distribution pole age profile in the South Shore sub-region.

Exhibit 4.107: South Shore sub-region Distribution Pole Age Profile

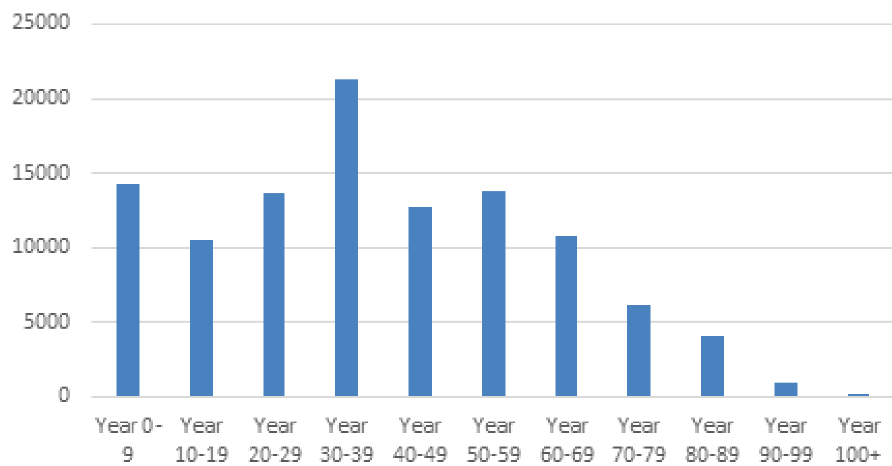
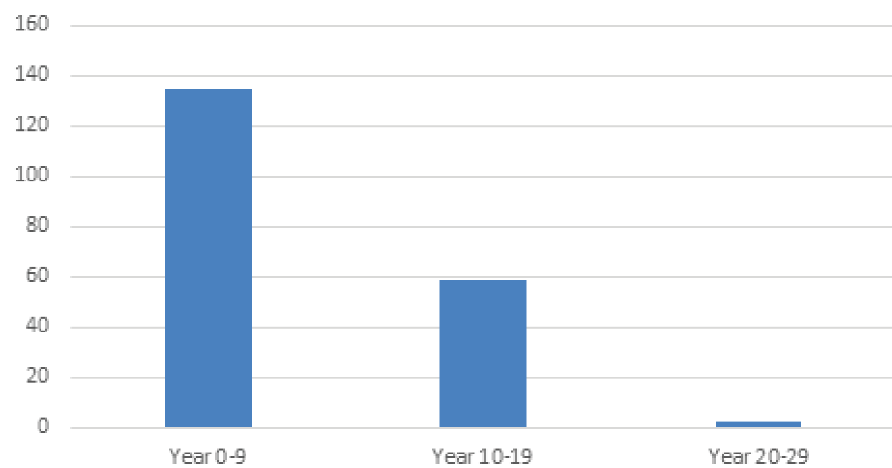


Exhibit 108 shows the reclosers' age profile in the South Shore sub-region.

Exhibit 4.108: South Shore sub-region Recloser Age Profile



4.7.9 Reliability and Resilience

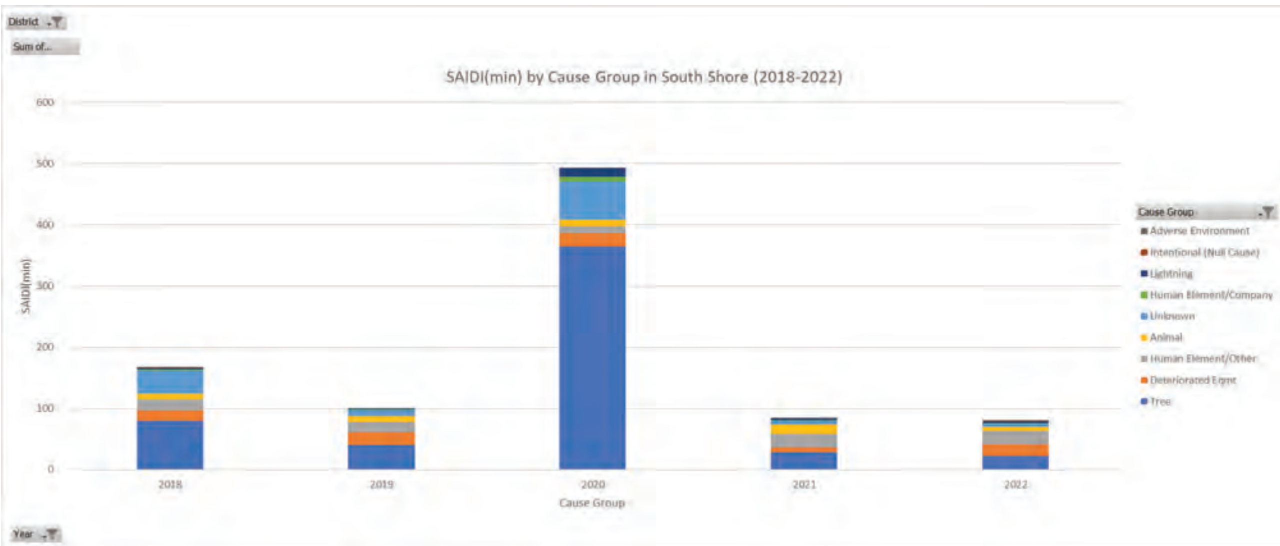
This section will describe how the Company reports reliability and what the current reliability metrics are for this given sub-region. For additional information on reliability, resiliency and company performance, the Company's annual report is here (Department Docket No. 12-120-D). This section is only illustrative for completeness of the system, and as such, relevant reliability investments are defined to be part of "core operations" and additional funding is not proposed in this plan. The investments proposed in this Future Grid Plan are driven by load growth and the need to increase system capacity.

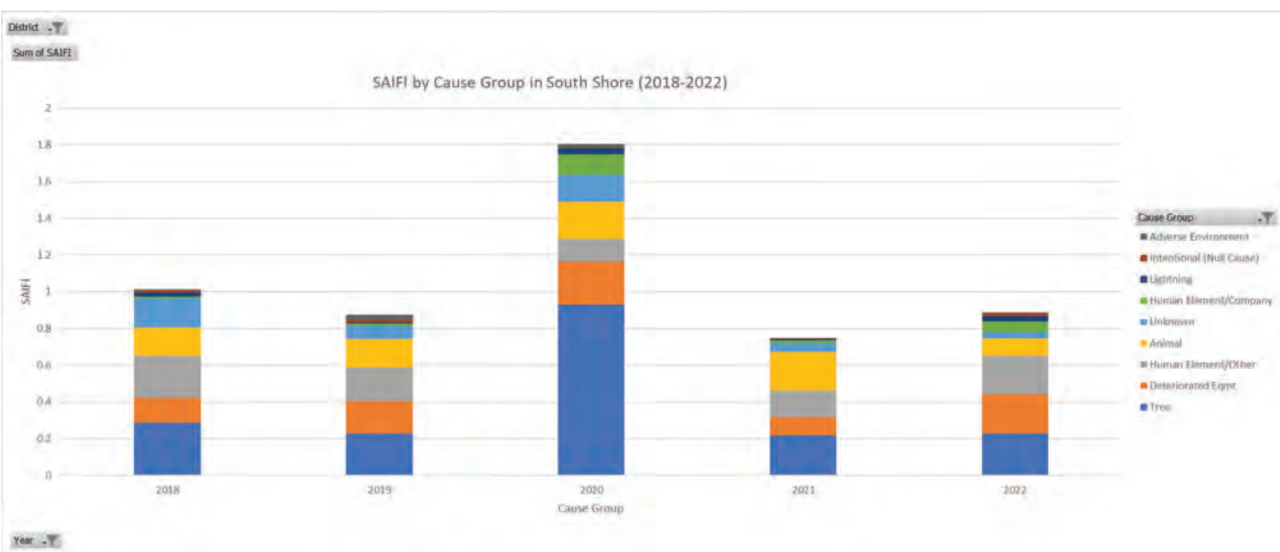
Refer to section 4.3.9 for background on reliability metrics and performance.

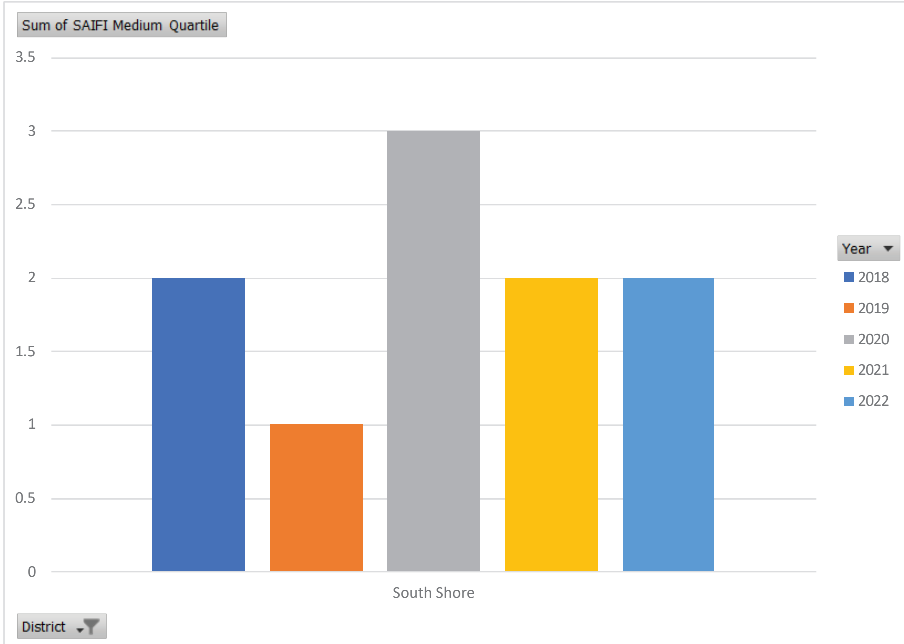
Reliability performance

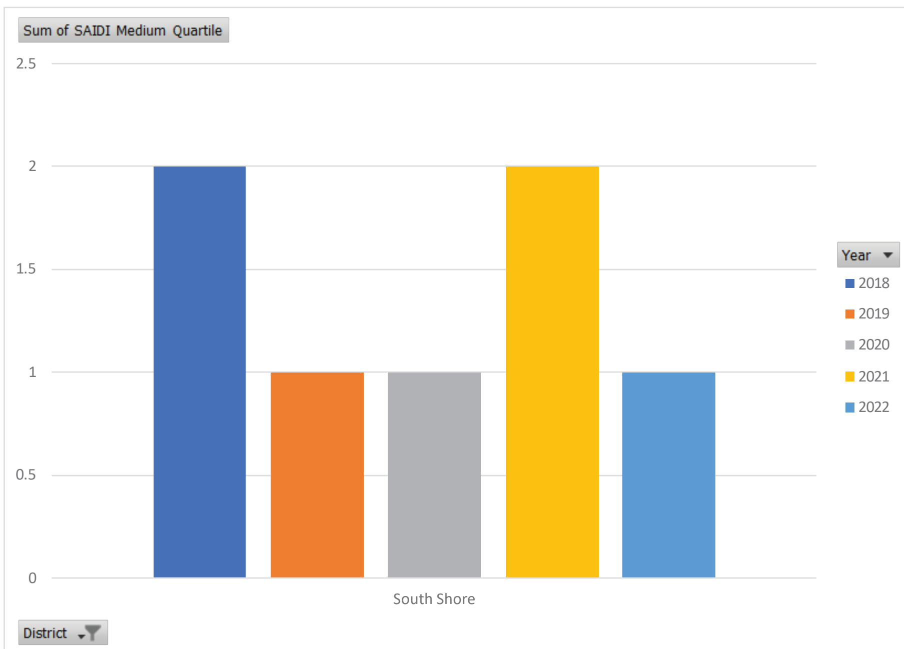
The exhibits below show the reliability performance of the sub-region in terms of duration (SAIDI) and frequency (SAIFI) of outages. The data in these Exhibits excludes major events, consistent with the Company's regulatory reporting criteria and call out leading causes of blue-sky outages for the region. Tree-related events caused most outages across this sub-region, in terms of duration and frequency.

Exhibit 4.109: South Shore sub-region Leading Causes of Blue-Sky Outages and SAIDI and SAIFI Reliability Performance









Refer to section 4.3.9 for background on how reliability metrics are calculated.

The IEEE Guide for Electric Power Distribution Reliability Indices (Standard 1366) was developed to facilitate uniformity in distribution service reliability indices and to aid in consistent reporting practices related to distribution systems, substations, circuits, and defined regions. While this methodology differs from the criteria applied to the Company's regulatory reliability reporting obligations, this approach was utilized to demonstrate the performance of the Company's distinct sub-regions as compared to similar size utilities responding to the survey (>100,000 - <1,000,000 customers). The benchmarking analysis showed that for four out of the last five years, the South Shore has been in the first or second quartile for frequency of outages (SAIFI) and has been in the first or second quartile for the past five years for duration (SAIDI).

Resiliency performance

As described in section 4.3.9, outage impacts from major events are traditionally excluded from reliability reporting, as described above. The Company calculated “all-in” SAIDI and SAIFI indices across its service territory to facilitate comparison of the resiliency and reliability challenges experienced in each sub-region relative to the others. This comparison highlights areas where emerging resiliency challenges have been experienced in the past five years. The methodologies that went into these calculations are described in section 4.3.9. Substations may have no reliability data for several reasons, including no recorded events over the time period or if they do not directly serve load to customers.

The following maps illustrate the substation resiliency of this sub-region overlaid with EJCs. The exhibits below show the Company’s distribution substation locations within the given sub-region overlaid with EJCs. Each distribution substation is color-coded indicating its five-year historical SAIDI or SAIFI performance relative to the Company’s entire population of substations. A greater density of distribution substations typically results in shorter distribution feeders with less outage exposure and increased numbers of feeder ties, resulting in better overall reliability. As can be seen in each of these Exhibits, substations in the EJCs predominantly fall within the top first and second quartile of SAIDI and SAIFI performance relative to the entire population of the Company’s distribution substations.

Exhibit 4.110: South Shore sub-region Resiliency in EJCs as shown as SAIDI Substation Performance

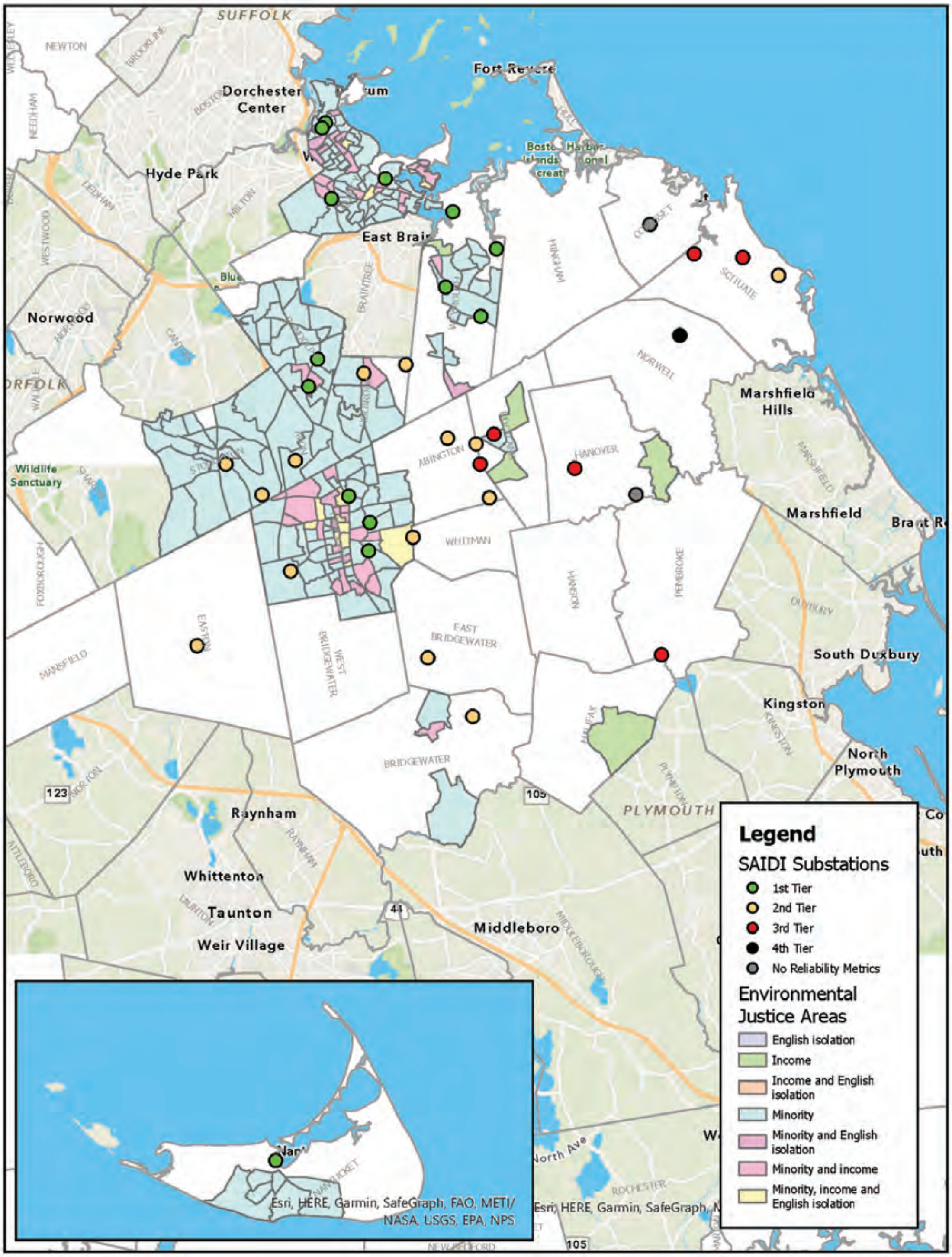
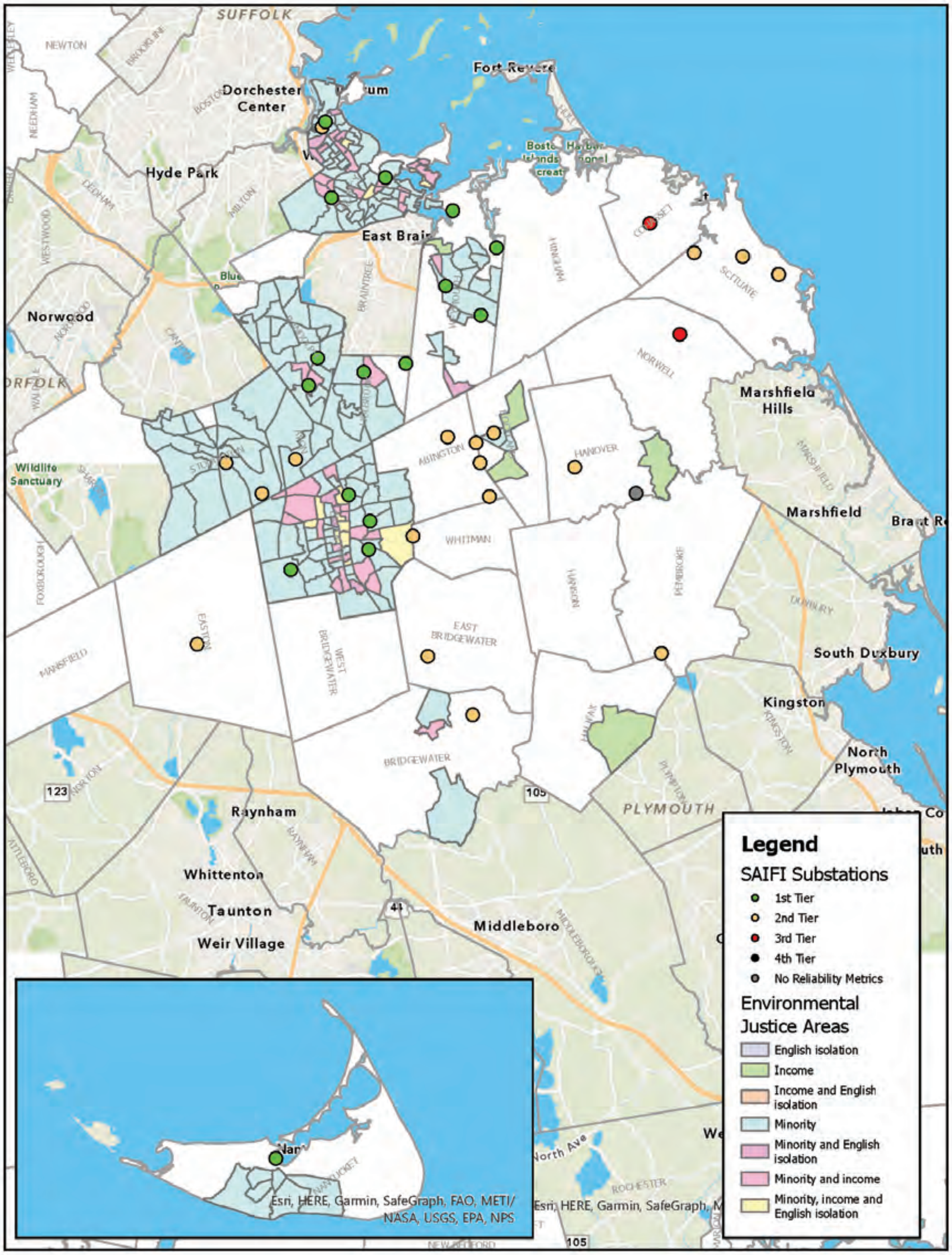


Exhibit 4.111: South Shore sub-region Resiliency in EJCs as shown as SAIFI Substation Performance



When looking at the 5-year performance, 2020 was particularly a bad year as the Company experienced 18 storm events that were not classified as major events. The impact of each event added together reflects the bad reliability performance at the system level. Also worth noting was that 2018 and 2021 were bad years of performance for the eastern part of the Company's Commonwealth service territory given three back-to-back storms occurring in early 2018 and a Nor'easter occurring in October 2021. As a result, substations in the fourth quartile of SAIDI/SAIFI performance can be seen in South Shore, Southeast and Merrimack Valley region maps.

4.7.10 Siting and Permitting

Energy infrastructure siting and permitting processes are generally consistent across the Commonwealth; therefore, siting and permitting challenges do not vary significantly by region. When projects require considerable underground transmission work, the EFSB review process is triggered to ensure the work is in compliance with State requirements. This EFSB review process is intended to take twelve months (see G.L. c. 164, Section 69J); however, the review timeline for recently submitted transmission line projects is trending toward 30 to 36 months.

Environmentally, the largest differences are at a municipal level rather than regionally. At the project-level, Conservation Commission impacts uniformly across the State but there is a high degree of variability town to town and year to year, which makes it challenging to generalize regionally.

There are no noteworthy environmental considerations for the South Shore sub-region except for the island of Nantucket. Nantucket has particular constraints around land scarcity and natural resource conservation. Project-level considerations are taken based on the local environmental considerations.

4.8 Western Sub-Region

The Western sub-region in brief:

Nature of the area: The Western sub-region is overwhelmingly rural, with regional urban centers in North Adams and Northampton.

The Company's customers' energy needs, economic circumstances and demographics in the Western sub-region vary greatly, which is why targeted, and culturally competent community engagement is at the core of the Company's plan to help the State achieve its goals.

Exhibit 4.112: Western sub-region customers by the numbers

Total Customers (accounts)	% Residential	% Business, Commercial, Municipal, or University	Benefits of EE	Heat Pump Adoption (end of 2022)	Total NG Charging Ports Installed
121,606	88%	12%	613,551 MWh	1,971	135 Ports

Exhibit 4.113: Western sub-region network by the numbers

Number of Substations	Number of Feeders	Total Length of Feeders	Total Peak Load Served	Square Miles of Region
29	90	3,250	418 MW	1,481

Context of the region

The Western sub-region is predominantly rural which has a more radial network. There are some more suburban areas in the region, but the network is very constrained in all areas. The Western sub-region has high levels of DERs penetration relative to all other sub-regions due to the large amount of open space compared to other areas of the Commonwealth. Due to growing suburban neighborhoods, an approximate 12.7% load growth is expected in the Western sub-region in the next 5 years. Additional details can be found in Section 5.

The Western sub-region is served by 29 substations supporting 90 circuits. Because of the way that the networks in the Western area have developed, the Company will need to undertake significant investment to meet the expected load growth. Due to land availability and land prices, this area has seen and continues to see a large number of DER applications interconnecting to the system that was intended to serve a more remote radial type of service.

The Western sub-region has some key characteristics which will drive investment needs in the future.

Exhibit 4.114: Western Sub-Region Key Characteristics that will Drive Future Investment Needs

Network Characteristic	Consequence
The majority of the distribution circuits in the region are 15 kV class circuits, which operate at voltages of 13.2 kV or 13.8 kV. While very few circuits are operated at 4.16 kV at their source, there are many 4.16 kV neighborhoods supplied by pole-mounted transformers that step voltages down to 4.16 kV more locally. This was a common practice in the past when converting circuits from 4.16 kV to 15 kV class voltages, to limit the scope of the conversion by continuing to operate local areas at 4.16 kV.	Areas served by these lower voltages will largely need to be converted to a higher voltage such as 13.2 kV or 13.8 kV in order to meet the significant load growth that is projected across the State. Voltage conversions can be costly and complex projects even at this local stepdown level, requiring widescale replacement or upgrade of significant amounts of distribution line facilities.
Population and load density in the Western sub-region leads to average feeder lengths that are 2-3 times the length of the average feeder in other sub-regions to serve approximately the same number of customers. These feeders are predominately overhead construction, through heavily treed areas.	Longer feeders have more exposure to outages, particularly outages due to trees falling over many miles of line exposure. With less dense substation infrastructure and fewer road-side routes available in rural areas, mitigating reliability exposure while accommodating load growth is particularly complex.
Lower historical load levels in the region have led to development of infrastructure with lower capacity. This includes both a sparsity of transmission facilities to supply new substations, and a high proportion of single transformer substations relative to other regions.	Accommodating load growth in the region will require expansion of existing single transformer substations, many of which were not originally designed to accommodate such an expansion, and installing significant new transmission facilities.
There is a high amount of DER penetration relative to load levels within the sub-region.	Many facilities within the sub-region experience power flow "backwards" from the distribution system to the transmission system, particularly during low-load seasons such as spring and fall. At times these backflow levels exceed equipment ratings. Additional DER interconnections in the region that are not offset by increasing electrification demand will require investment to create additional generation hosting capacity.

4.8.1 Maps

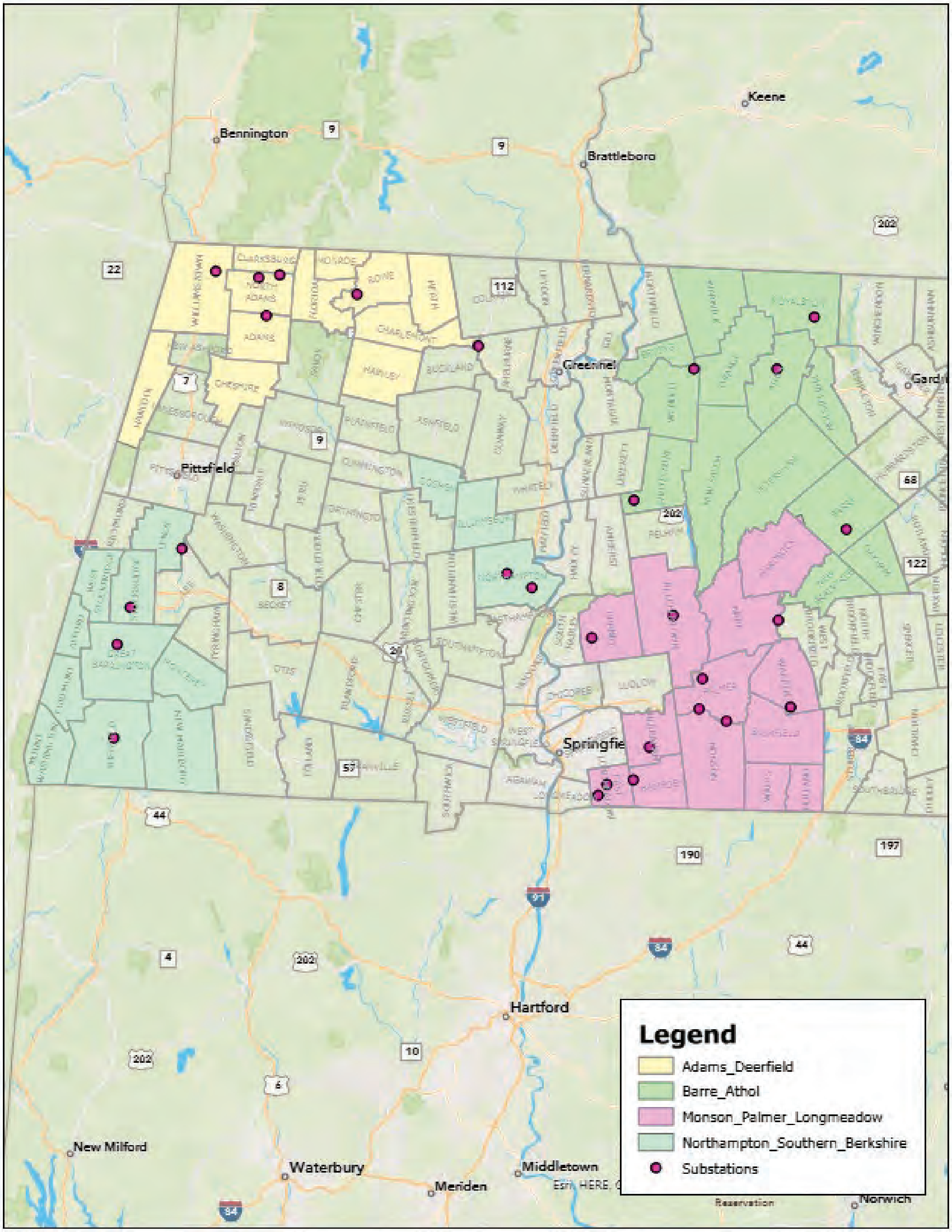
The Western sub-region consists of 51 towns and cities and comprises the study areas below:

Exhibit 4.115: Western Sub-Region Study Areas and Towns

	Study Area	Town
1	Adams/Deerfield	Adams, Charlemont, Cheshire, Clarksburg, Florida, Hancock, Hawley, Heath, Monroe, North Adams, Rowe, Williamstown
2	Barre/Athol	Athol, Barre, Erving, Hardwick, New Braintree, New Salem, Oakham, Orange, Petersham, Phillipston, Royalston, Shutesbury, Ware, Warwick, Wendell
3	Monson/Palmer/Longmeadow	Barre, Belchertown, Brimfield, East Longmeadow, Granby, Hampden, Hardwick, Holland, Monson, New Salem, Palmer, Wales, Ware, Warren, Wilbraham
4	Northampton/southern Berkshire	Alford, Egremont, Goshen, Great Barrington, Lenox, Monterey, Mount Washington, New Marlboro, Northampton, Sheffield, Stockbridge, West Stockbridge, Williamsburg

Exhibit 4.116 below shows the substation locations within the Western sub-region's study areas, indicated with a red dot. Note that not all study areas cleanly follow town lines because they are defined electrically instead of geographically.

Exhibit 4.116: Western sub-region Substation Locations and Study Areas



4.8.2 Customer Demographics

Exhibit 4.117: Western sub-region customer demographics summary

Number of Customers				Residential Population Growth	Benefits of EE	Existing Connected Rooftop DER (< 25kW)
Total	Residential – Total	Residential – Low Income Rate Participants	Commercial	5-year Growth Projections		
121,606	106,467	15,509	15,139	0.05%	613,551 MWh	79MW

The Company serves a total of 121,606 customers (defined by individual accounts, not the number of people served) – in the Western sub-region. Approximately 88% (106,467) of these customers are residential customers and the other 12% are comprised of commercial, municipal, or university customers.

Population growth in this region is forecasted to be considerably lower than the other sub-regions due to historical census data and expected trends in highly rural areas[21].

In addition to the Mass Save programs which have benefited customers in the central region, 24 towns statewide have been identified for targeted outreach per MA EEAC Equity Working Group plans. Under these outreach plans the Company is specifically working to encourage more Energy Efficiency benefits in low-adoption zones. The towns/cities included in the Central region are: North Adams, Palmer, Great Barrington, and Northampton.

The Company recognizes that a significant portion of the Company's customers live in EJCs, which are disbursed throughout the Company's service area. Historically, EJCs have borne the highest energy burdens and been disproportionately impacted by the fossil-based economy. As outlined earlier in Section 3.3, the Company is developing a formal Equity and Environmental Justice Policy and Engagement Framework, as well as complementary policy and framework focused on Indigenous Peoples, which the Company will seek feedback on from those communities prior to finalizing, please refer to the Appendix for those drafts.

Exhibit 4.118 below is a map that overlays current substation locations with the Commonwealth's Environmental Justice maps, updated in 2022. Exhibit 4.118 below highlights concentrations of substations in many load-dense areas – town centers and other major economic areas with existing industry, or a history of industry. Load density and electric capacity needs are the key drivers to substation density and location. As the load increases, the need for more substations to serve these population centers and expanding rural areas will increase too. Many Environmental Justice Areas have been identified as such by the Commonwealth because they have been historically unduly burdened by infrastructure and related pollution. As discussed in Section 3, the Company is committed to being a trusted partner with all the Company's host communities, including those which contain Environmental Justice Populations, as new infrastructure needs to be built throughout the Commonwealth to reach decarbonization and electrification goals. Additional infrastructure that has yet to be built per recommendations in this Future Grid Plan and as part of existing investment plans can be found in Section 6.

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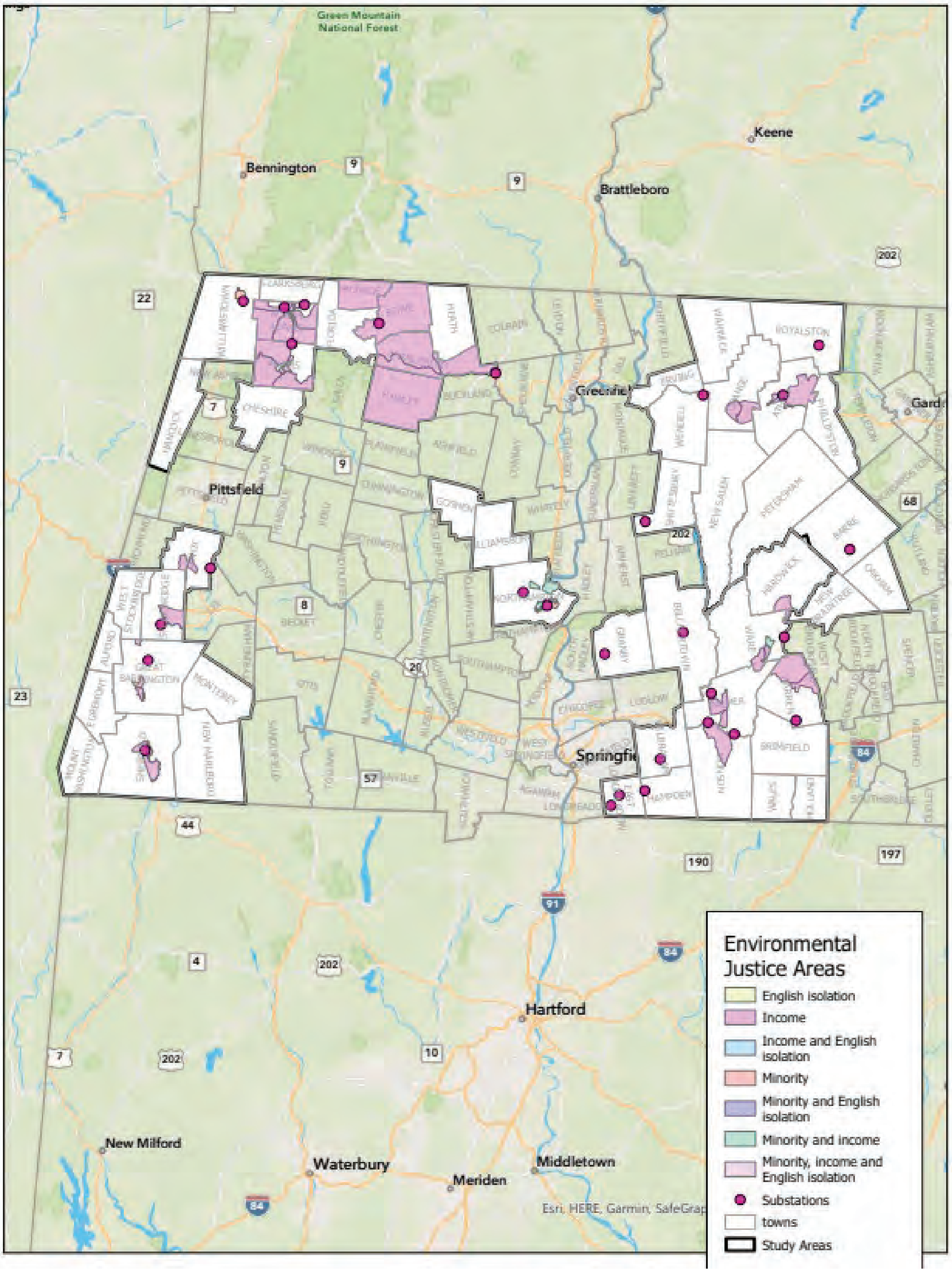
[21] Analysis of data from https://data.census.gov/

Exhibit 4.118: Western sub-region substations with to the Commonwealth's EJC map



4.8.3 Economic Development

The development of the Company's Plan was informed, in part, by the varying levels of readiness within each sub-region. Within the Company's study areas defined in the Future Grid Plan, 14 communities have completed decarbonization plans and 139 are designated as "green communities" under M.G.L. c. 25A §10. In partnership with the Company, the following municipalities have completed a Strategic Energy Management Plan (SEMP): Athol, Beverly, Everett, Lowell, Melrose, Newburyport, and Salem. The Company anticipates one new SEMP to be signed before the end of the year, with an additional five SEMPs in the development queue

In the Western sub-region, three communities (North Adams, Athol, and Northampton) have completed decarbonization plans, 38 are designated as green communities, and one community, in partnership with the Company, has completed a SEMP. Over the last decade, the region has focused on reconstructing the North-South "knowledge corridor" and East-West "inland route" rail trail corridors to promote passenger and freight traffic. The FY19-24 CEDS highlighted the region's aspiration to lead the Commonwealth's clean energy transformation, with the specific goals of achieving 600 million kWh of new clean energy generation and a reduction of 3.2 metric tons of GHG. The strategy emphasizes the ongoing challenge posed by the region's fragile infrastructure systems and the need to increase investment levels across the region.

4.8.4 Electrification Growth

Heat Electrification - The Western sub-region has moderate pump adoption compared to the other five sub-regions with about 1,100 units adopted by the end of 2022, of which over 60% are hybrid.

Transport Electrification – There has been steady growth in LDEV sales in the Western sub-region, although with about 3,380 vehicles as of the end of 2022, the Western sub-region has the lowest number of EVs among all sub-regions. Additionally, there are no MHDEVs at present. Since 2019, The Company has installed 135 EV charging ports via their phase I and phase II EV charging programs in the Western sub-region.

4.8.5 DER Adoption (Battery Storage and Solar Photovoltaic)

With a total of 515 MW of generation connected, the Western sub-region has relatively high DER penetration. Connected DER is predominately solar, representing 92% of the installed DER capacity in the Western sub-region.

Exhibit 4.119: Western sub-region DER adoption summary

Sub-Region	Solar (MW)	Battery (MW)	Hydro (MW)	Wind (MW)	Miscellaneous[1] (MW)	Grand Total (MW)
Western – Connected DER	416.9	63.4	1.9	9.0	29.8	521.6

Significant levels of DER have been connected in the Western sub-region, predominately in the past decade. Note that in Exhibit 4.120, the 2023 value is reflective of year-to-date interconnections as of \July 2023.

Exhibit 4.120: Cumulative Connected Generation and Storage – Western Sub-Region

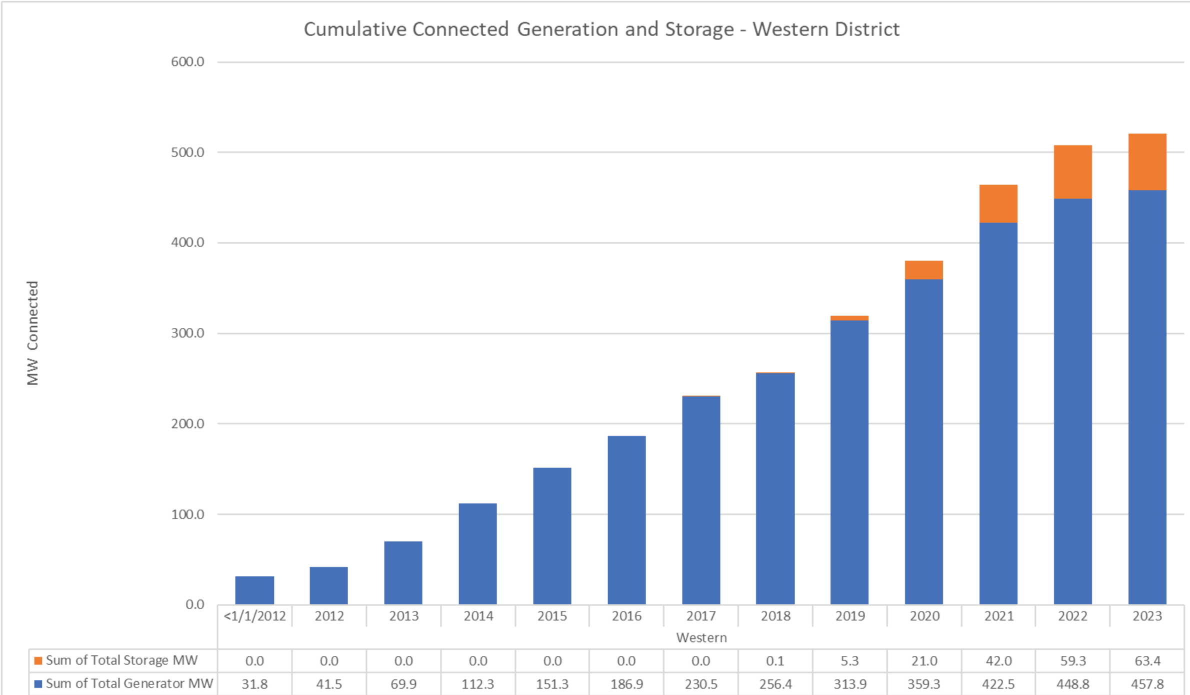


Exhibit 4.122 below contains visibility of the current DER interconnection queue in the Western sub-region. Recent application trends have demonstrated a shift from largely solar PV applications to a split between solar PV and battery storage, with solar PV representing 62% and batteries representing 35% of the current queued DER capacity.

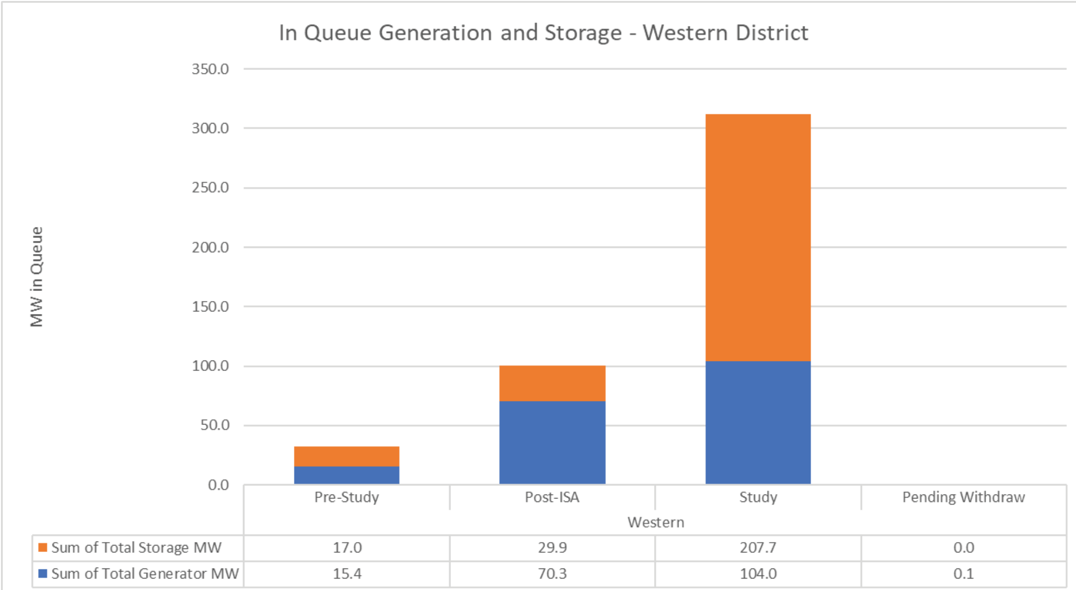
A large majority of the batteries are stand-alone, albeit some are co-located as PV paired with storage. Unlike other forms of DER, which operate solely in a discharge or export capacity, contributing power to the grid, standalone batteries also must charge from the grid. While solar and other forms of DER, excluding batteries, only require there to be sufficient grid *hosting* capacity for their interconnection, batteries require both hosting and load-serving capacity at the location of their interconnection. Therefore, batteries are subject to capacity deficiency (i.e., charge) considerations such as those highlighted in Section 4.8.7 as well as any hosting capacity (i.e., discharge) constraints that may be present.

This significantly increases the complexity of planning and operating the network.

Exhibit 4.122: Western sub-region pending DER Generation and Storage in queue

Sub-Region	Solar (MW)	Battery (MW)	Hydro (MW)	Wind (MW)	Miscellaneous[2] (MW)	Grand Total (MW)
Western – Pending DER	167.2	253.2	0.2	0.0	10.6	431.2

Exhibit 4.121: In Queue Generation and Storage – Western Sub-Region



	Pre-Study	Post-ISA	Study	Pending Withdraw
Sum of Total Storage MW	17.0	29.9	207.7	0.0
Sum of Total Generator MW	15.4	70.3	104.0	0.1

Combining the 431.2MW in the interconnection queue, and the 521.6MW already connected in the Western sub-sub-region, the total for the area would be 952.8MW if all in-queue projects move forward. While it is unlikely that all will connect, this would be a doubling of interconnected DER in an already constrained area and would therefore require significant infrastructure expansion.

There are CIP proceedings underway in this area under the following dockets:

- Barre Athol (Department Docket No. 23-12)
- Monson Palmer East (Department Docket No. (22-170)
- Shutesbury (Department Docket No. 22-61)

In the Western sub-region, the Company has analysis completed or in progress for group study for the interconnection of DER in the following study areas[3]:

- Monson Palmer Northwest

The proposed DER and system modifications required for the proposed groups have been included in the base case for this Future Grid Plan analysis; should the DER customers in these groups not proceed to interconnection, the investments described in will need to be analyzed for the impacts of this attrition and adjusted appropriately. The Company is proposing to apply CIP cost allocation principles to these investments once they reach sufficient maturity.

The high-level benefits of the CIPs to distribution customers include:

- Reliability: the solution proposed to safely and reliably interconnect group study DER, in many cases coincidently, addresses existing or projected system needs. The proposed upgrades, if approved, expedite addressing these reliability concerns. These include:
    - EPS normal configuration thermal loading
    - EPS contingency configuration customer unserved
    - EPS asset conditions
- Enabled electrification: the proposed solution in some cases also provide thermal capacity beyond the planning horizon and support some loading projects out to 2050.

- Reserved Small DG: the proposed solutions also incorporate a reserved capacity on each study feeder for the small rooftops to interconnect without triggering major EPS upgrades, which typically is a direct benefit to distribution customers.

The high-level description of the common system modifications required to accommodate the interconnection of the DER included in the groups listed above are included in the Appendix. Note that these areas are in various stages of maturity and the modifications identified below are subject to change pending further analysis through the group study process. Cumulatively, in order to interconnect the 19 MW of DER proposed through the current group studies, the Company anticipates requiring system modifications that include the addition or upgrade of 2 substation transformers and approximately 2 miles of distribution line construction, at an estimated cost of $21M.

4.8.6 Grid Services (Demand Response, Smart inverter Controls, Time-varying Rates)

The Company currently offers several grid service participation opportunities to residential and commercial customers through its Demand Response and EV managed charging programs. Customers can earn incentives for curtailing load, pre-cooling with smart thermostats, charging their electric vehicles at optimal times, or shifting energy use with battery storage during peak load periods. As described in sections 6.3, 6.11, and 9.3 and 9.6 the Company is also on a path toward expanding grid services via AMI and time-varying rates, and leveraging DERMS technology investments to offer more dynamic, location-specific grid services as NWA solutions in the future.

In the Western sub-region, over 2,000 customers currently participate in ConnectedSolutions DR program and help to reduce approximately 19 MW of load on the grid when the overall grid is at peak.

4.8.7 Capacity Deficiency

The exhibits below summarize the asset loading across the Western sub-region in 2023. The 2023 loading profile shows that most assets are loaded below 75% of their normal rating.

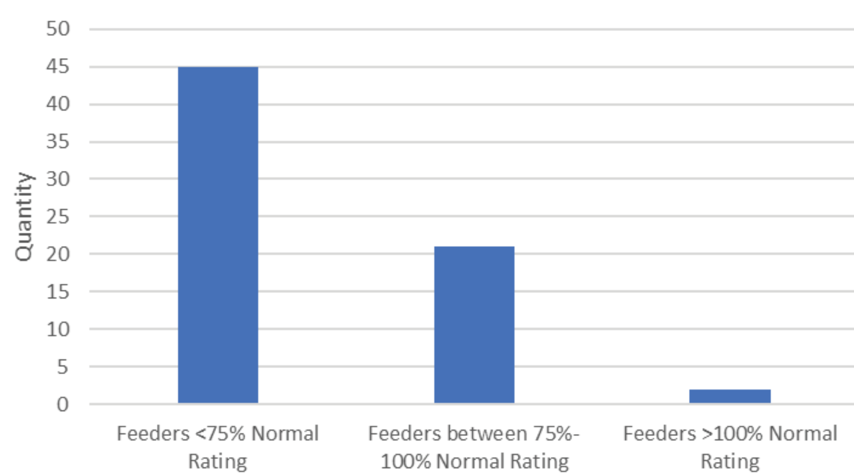
Exhibit 4.123: 2023 Forecasted Transformer Loading Profile – Western Sub-Region

Substation transformer capacity deficiencies exist in the following areas:

Exhibit 4.124: Western sub-region pending DER Generation and Storage in queue

Study Area	Substation	Capacity Deficiency
Barre-Athol	BARRE 604	Transformers > 100% Emergency Rating in Contingency

Exhibit 4.125: 2023 Forecasted Feeder Loading Profile – Western Sub-Region



Two feeders in the Western sub-region have an identified existing capacity deficiency; this deficiency is being monitored as an anticipated spot load comes into service, and operational mitigations will manage the overload as appropriate. One of the overloaded feeders is a reverse flow overload due to the interconnected DER on the feeder.

The Western sub-region features a 23 kV sub-transmission system in the Adams/Deerfield area that supplies most of the study area through the Adams Substation. The Adams Substation serves approximately 70 MW of load and supplies three substations which step the voltage down from 23kV to 13kV. The Adams 23kV system has normal and contingency loading concerns that limit the amount of load growth that can be supported by the Adams substation.

The Northampton/South Berkshire study area is primarily supplied by a transmission and sub-transmission network owned by Eversource. The Northampton area is supplied by a combination of 115kV and 13.8kV from the Midway substation. The South Berkshire area is supplied by 23kV supply lines from the Pleasant 16B and Woodland substations. The study area will have normal and contingency loading concerns that limit the amount of load growth that can be supported by the sub-transmission supplies from the Eversource owned network. Infrastructure investments in these areas must consider Eversource as a critical stakeholder.

4.8.8 Aging Infrastructure

This section is only illustrative for completeness of the system, and as such, relevant aging infrastructure investments are defined to be part of “core operations” and additional funding is not proposed in this plan. The investments proposed in this Future Grid Plan are driven by load growth and the need to increase system capacity.

As energy infrastructure ages, and often consequently, its condition worsens, the risk of equipment failure increases and the reliability of operation decreases. The age of infrastructure is an important consideration when assessing the condition of assets and in efforts to meet the future demands of the network. However, asset replacement is driven primarily by asset condition rather than time of life. The Company’s approach to maintenance has moved from a time-based approach to risk and condition based as a result of digitizing information and having real-time data. Substations and distribution lines are surveyed regularly to assess asset health and to make recommendations for replacement.

Assets are rated based on a range of criteria to assess their health, which drives asset condition replacement projects. Standard maintenance and regular testing (e.g., inspecting and replacing subcomponents of a circuit breaker) can enhance reliability and extend the life of specific assets. Often, assets exceed their life expectancy if their condition and risk profile allow it, enabling the Company to maximize the value of assets while maintaining network reliability.

Additionally, as the Company moves towards modernizing and standardizing the grid and/or substations, existing equipment may need to be modified or replaced in order to digitize current methods. It is important the Company remains diligent in improving their infrastructure with new technologies and remains environmentally focused. (e.g., changing substation support structure design from aluminum to steel due to efficiency and decarbonization).

Exhibit 4.126 below shows the metalclad age profile in the Western sub-region.

Exhibit 4.126: The Metalclad Age Profile – Western Sub-Region

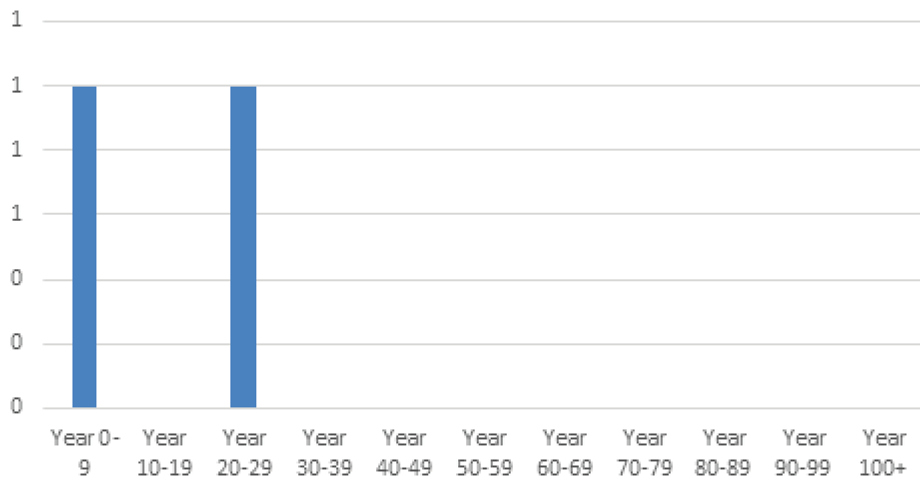


Exhibit 4.127 below shows the transformer age profile in the Western sub-region.

Exhibit 4.127: Substation Transformer Age Profile – Western Sub-region

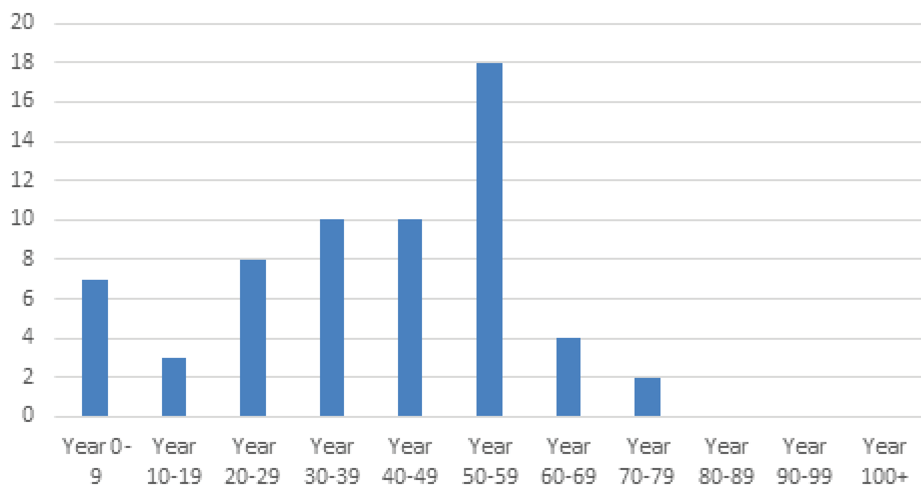


Exhibit 4.128 below shows the distribution pole age profile in the Western sub-region

Exhibit 4.128: Distribution Pole Age Profile – Western Sub-Region

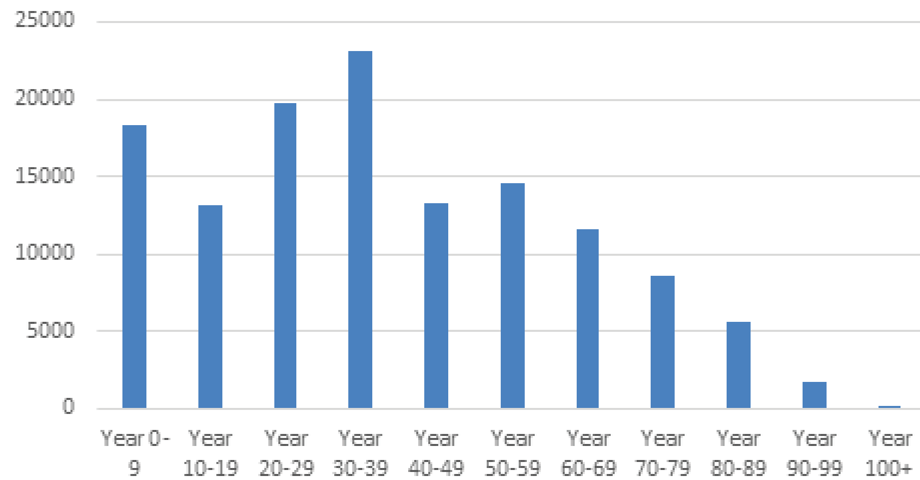
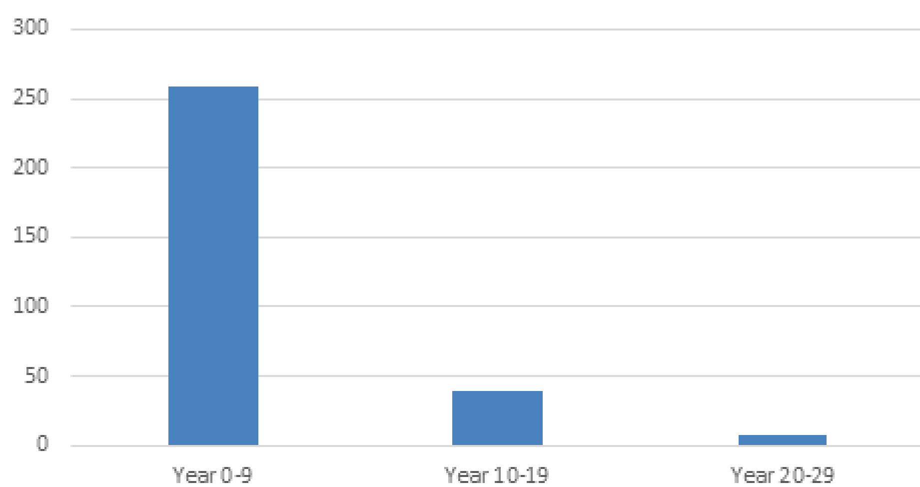


Exhibit 4.129 below shows the recloser age profile in the Western sub-region.

Exhibit 4.129: Recloser Age Profile – Western Sub-Region



4.8.9 Reliability and resilience

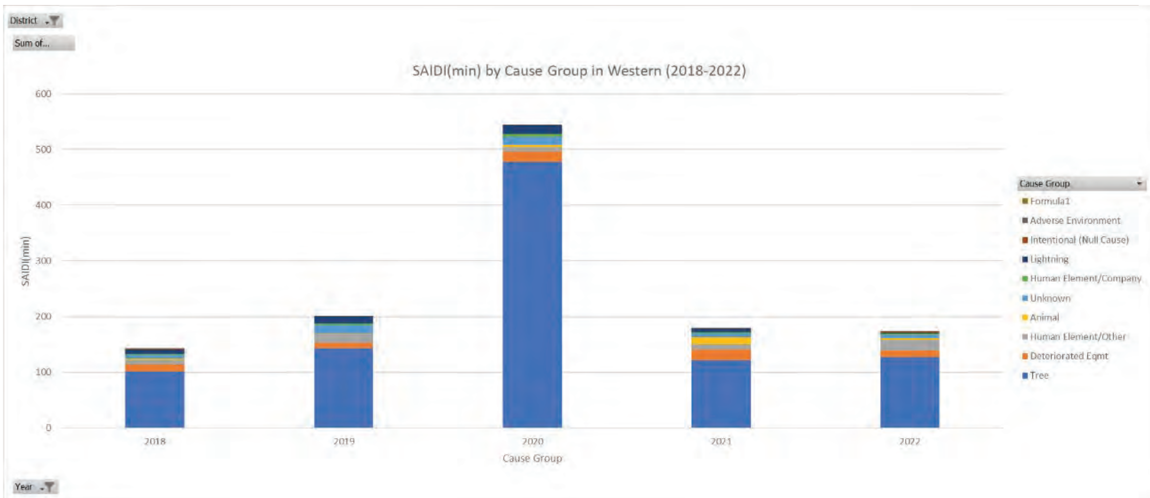
This section will describe how the Company reports reliability and what the current reliability metrics are for this given sub-region. For additional information on reliability, resiliency and company performance, the Company's annual report is here (Department Docket No. 12-120-D). This section is only illustrative for completeness of the system, and as such, relevant reliability investments are defined to be part of "core operations" and additional funding is not proposed in this plan. The investments proposed in this Future Grid Plan are driven by load growth and the need to increase system capacity.

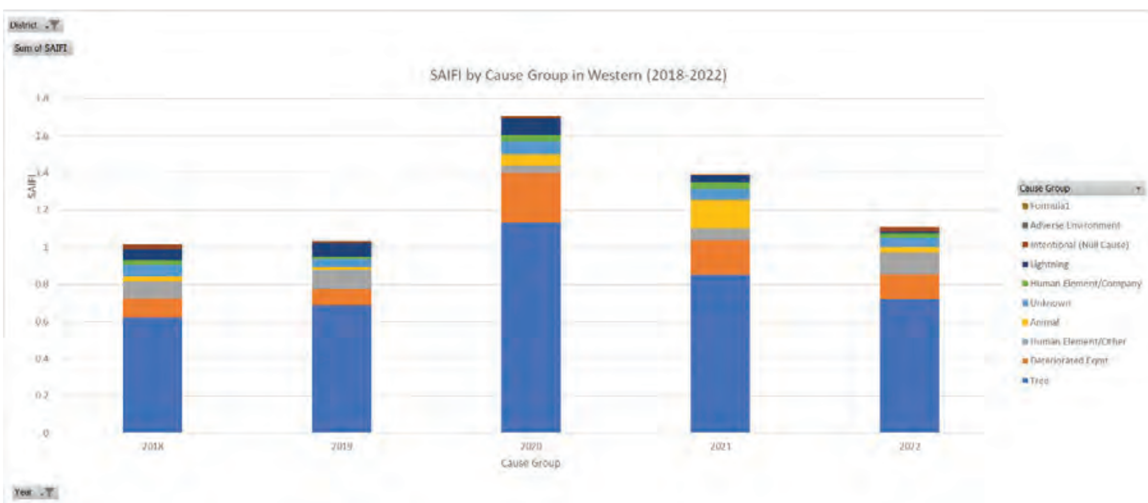
Refer to section 4.3.9 for background on reliability metrics and performance.

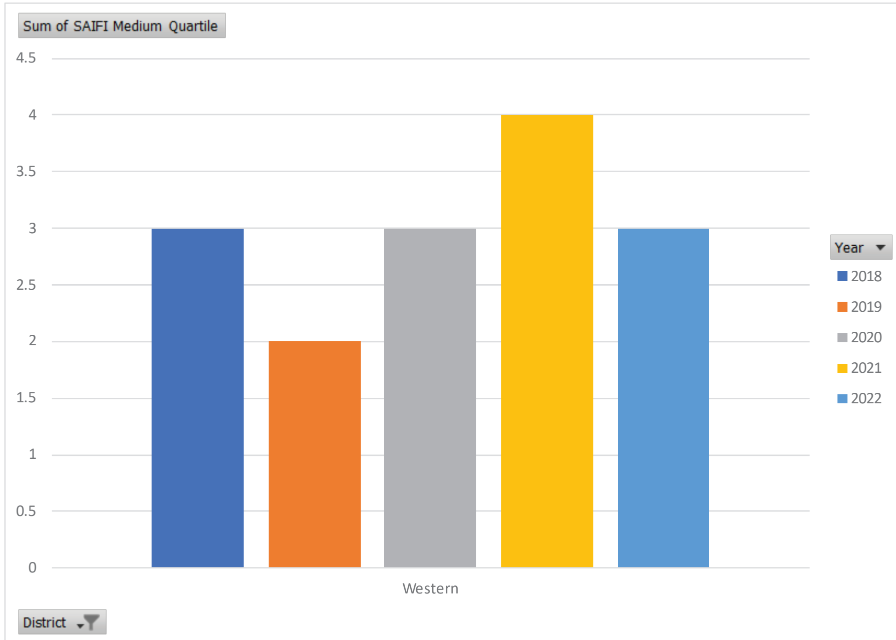
Reliability performance

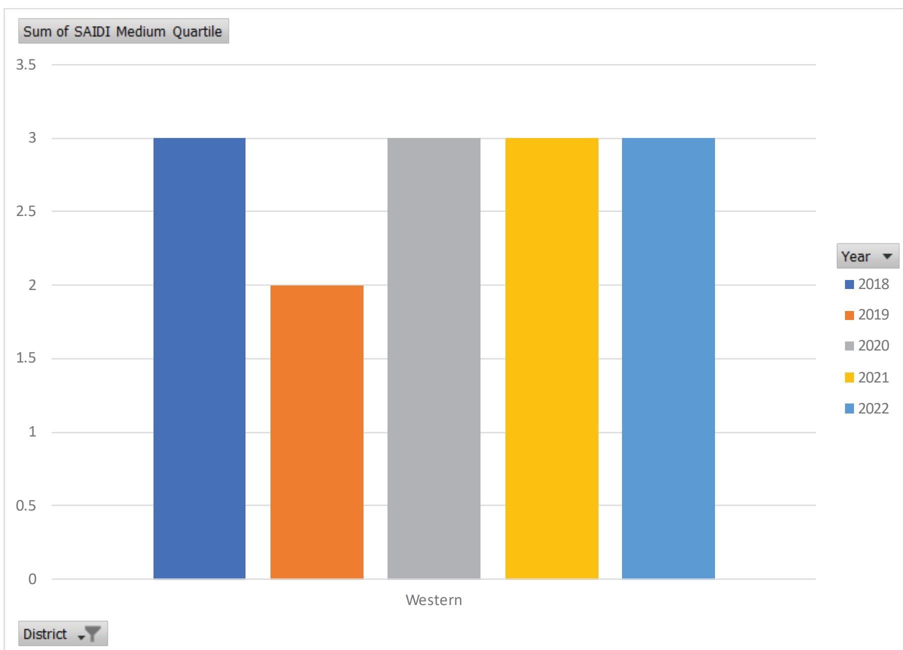
The exhibits below show the reliability performance of the sub-region in terms of duration (SAIDI) and frequency (SAIFI) of outages. The data in these Exhibits excludes major events, consistent with the Company's regulatory reporting criteria and call out leading causes of blue-sky outages for the region. Tree-related events caused most outages across this sub-region, in terms of duration and frequency.

Exhibit 4.130: Western Leading Causes of Blue-Sky Outages and SAIDI and SAIFI Reliability Performance









Refer to section 4.3.9 for background on how reliability metrics are calculated.

The IEEE Guide for Electric Power Distribution Reliability Indices (Standard 1366) was developed to facilitate uniformity in distribution service reliability indices and to aid in consistent reporting practices related to distribution systems, substations, circuits, and defined regions. While this methodology differs from the criteria applied to the Company's regulatory reliability reporting obligations, this approach was utilized to demonstrate the performance of the Company's distinct sub-regions as compared to similar size utilities responding to the survey (>100,000 - <1,000,000 customers). The benchmarking analysis showed that for four out of the last five years, Western has been in the second or third quartile for frequency of outages (SAIFI) and has been in the second or third quartile for the past five years for duration (SAIDI).

Resiliency performance

As described in section 4.3.9, outage impacts from major events are traditionally excluded from reliability reporting, as described above. The Company calculated “all-in” SAIDI and SAIFI indices across its service territory to facilitate comparison of the resiliency and reliability challenges experienced in each sub-region relative to the others. This comparison highlights areas where emerging resiliency challenges have been experienced in the past five years. The methodologies that went into these calculations are described in section 4.3.9. Substations may have no reliability data for several reasons, including no recorded events over the time period or if they do not directly serve load to customers.

The following maps illustrate the substation resiliency of this sub-region overlaid with EJCs. The exhibits below show the Company’s distribution substation locations within the given sub-region overlaid with Environmental Justice Areas. Each distribution substation is color-coded indicating its five-year historical SAIDI or SAIFI performance relative to the Company’s entire population of substations. A greater density of distribution substations typically results in shorter distribution feeders with less outage exposure and increased numbers of feeder ties, resulting in better overall reliability. As can be seen in each of these Exhibits, substations in the Environmental Justice areas fall within the top first and second quartile of SAIDI and SAIFI performance relative to the entire population of the Company’s distribution substations.

Exhibit 4.131: Resiliency in EJCs as shown as SAIDI Substation Performance

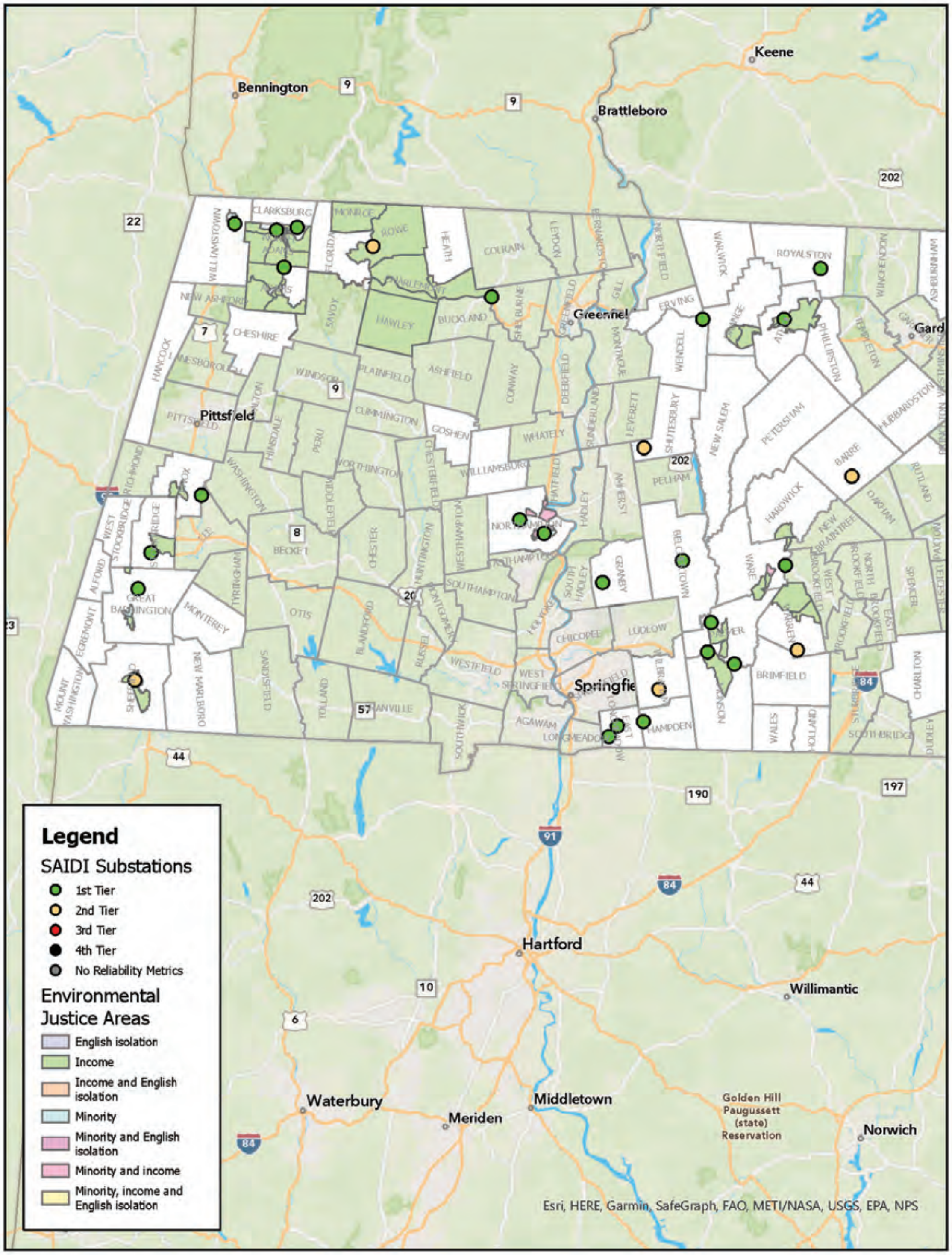
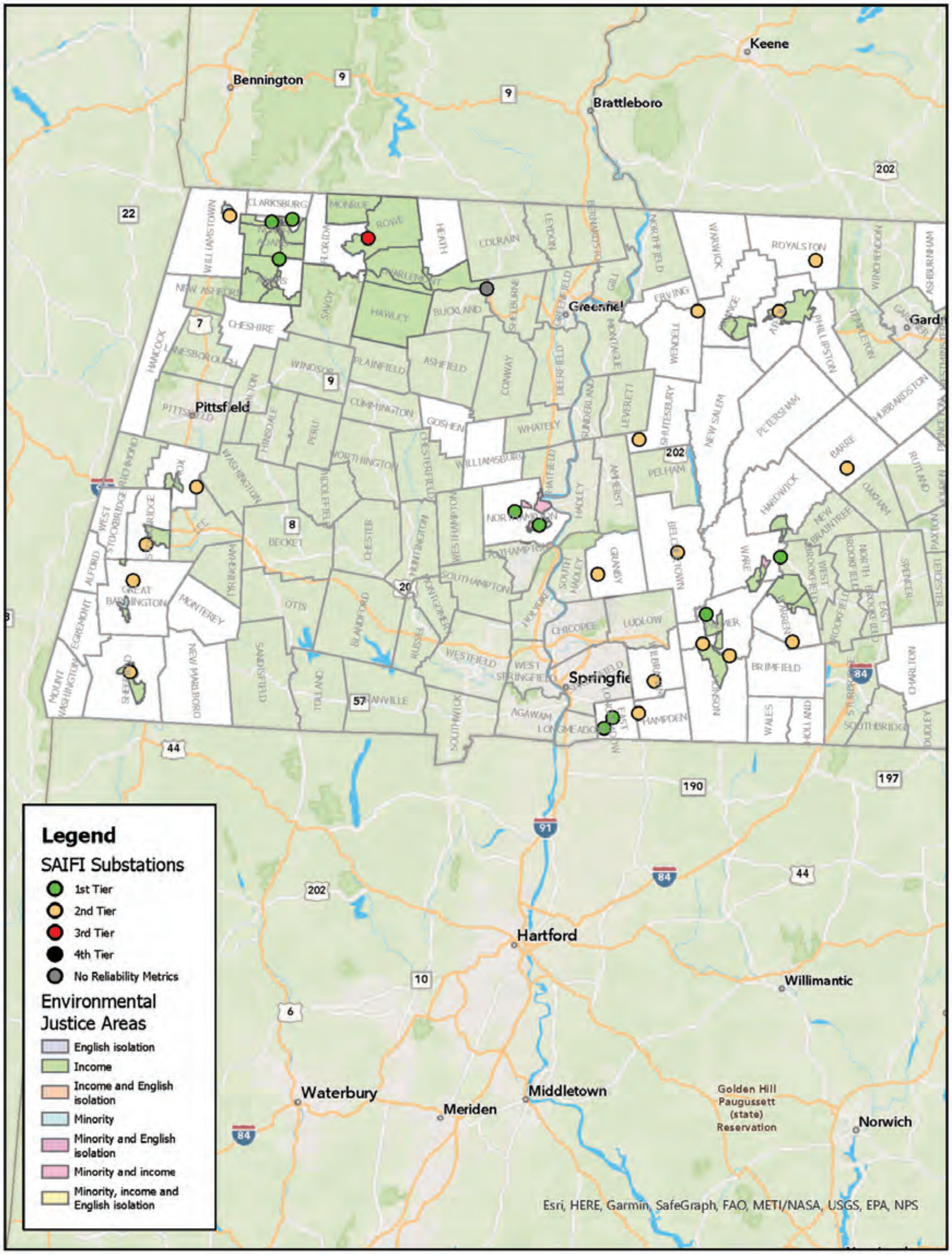


Exhibit 4.132: Resiliency in EJCs as shown as SAIFI Substation Performance



When looking at the 5-year performance, 2020 was particularly a bad year as the Company experienced 18 storm events that were not classified as major events. The impact of each event added together reflects the bad reliability performance at the system level. Also worth noting was that 2018 and 2021 were bad years of performance for the eastern part of the Company's Commonwealth service territory given three back-to-back storms occurring in early 2018 and a Nor'easter occurring in October 2021. As a result, substations in the fourth quartile of SAIDI/SAIFI performance can be seen in South Shore, Southeast and Merrimack Valley region maps.

4.8.10 Siting and Permitting

Energy infrastructure siting and permitting processes are generally consistent across the Commonwealth; therefore, siting and permitting challenges do not vary significantly by region. When projects require considerable underground transmission work, the EFSB review process is triggered to ensure the work is in compliance with State requirements. This EFSB review process is intended to take twelve months (see G.L. c. 164, Section 69J); however, the review timeline for recently submitted transmission line projects is trending toward 30 to 36 months.

Environmentally, the largest differences are at a municipal level rather than regionally. At the project-level, Conservation Commission impacts uniformly across the State but there is a high degree of variability town to town and year to year, which makes it challenging to generalize regionally.

There are no noteworthy environmental considerations for this sub-region. Project-level considerations are taken based on the local environmental considerations.

4.9 Technology Platforms that the Company Has in Place Today

To operate, manage and control the network for the benefit of customers the Company uses a range of technology and communication platforms. Many of these systems were designed to operate a simpler network and need to be upgraded to meet the needs of the clean energy transition.

This section will briefly highlight several of the technology platforms that are in place today, which are discussed in the following sub-categories.

1. **Network management and communications** includes the technologies used to communicate with, monitor and control assets on the network and to manage and respond to grid outages and abnormal system conditions.
2. **Metering and billing systems** includes the technologies used to measure customer energy usage on the grid and issue accurate bills based on those meter reads.
3. **Customer portals** includes the customer-facing and internal systems leveraged today to manage customer programs such as those related to Energy Efficiency, EVs, and new customer interconnections.
4. **Data** includes the type of data that the Company's network planning and operations and customers have access to, as well as the ability to manage, integrate, and operationalize that data to transform how the grid is operated and planned.
5. **Asset planning, management, and work execution** includes the systems that the Company uses to support grid planning and design, construction and capital deployment, and regular system maintenance and field operations.
6. **Security** includes measures in place to ensure the security of technology systems from potential cyber threats and attacks.

Network management and communications

- Energy management system: The Company for several years has leveraged a centralized Energy Management System (EMS), which provides remote interval monitoring and control for a variety of substation and circuit equipment on both the transmission and distribution system for assets where real-time telemetering has been installed. The tool is relied on heavily by control room operators in the Company's distribution and transmission control centers to provide the best available "real-time" feeds of system conditions. While the EMS includes many distribution network assets, the EMS is primarily designed around transmission use cases. For instance, the EMS performs balanced load flow analysis for the transmission system, though it is not capable of implementing load flow analysis for the unbalanced systems (i.e., single phase systems) that comprise the majority of the distribution network.
- Outage Management System (OMS): In addition to EMS, the Company has utilized an OMS to manage calls and outages. OMS tightly integrates with the call center to provide timely, accurate and customer-specific outage information. OMS also takes these calls and aggregates them on a connected network model of the distribution grid and makes outage predictions to the next level interruptible device to assist in routing crews for response and repair. OMS tracks customer estimated time of restoration, crew assignment and arrival details and outage cause and condition information to supply other downstream reporting and communications.
- Communications The Company utilizes a combination of private telecom networks and leased wired and wireless circuits and services to meet its mission-critical communications needs such as corporate enterprise functions, teleprotection, Supervisory Control and Data Acquisition (SCADA) communications, physical security required at facilities, grid edge devices, off-site data center connectivity, and Company facility interconnections. These networks are also used to support telemetered communications to larger scale DER (500 kw+) based on current interconnection requirements. The telecom backbone consists of private fiber optic and high-capacity microwave networks. While the existing communications network has supported legacy grid data requirements, it must be upgraded and expanded to support future grid modernization efforts and enable greater reliability, control, monitoring, and security of the assets. In particular, as will be discussed in Section 6, the existing communications network is not fit for purpose for the envisioned future intelligent network operation that involves more dynamic and interactive network management, particularly as DER adoption expands and creates new opportunities to better integrate customer devices into grid operations.

Metering and billing systems

- The Company's meters today are part of an Automated Meter Reading (AMR) system. Deployed in the early 2000s to replace manual meter reading processes, this technology sends a radio signal to a fleet of service vans as they drive by to collect monthly meter reads. The AMR technology contains core features that the Company relies on for identifying customer load, issuing accurate customer bills based on their electricity consumption, and managing customer connections to the Company's infrastructure. The meters function like an odometer in a car, keeping a total tally of net energy consumption on a monthly basis. However, the meters do not have the functionality to collect interval meter reads (i.e., hourly, or sub-hourly energy usage) and support TVR, provide customers with detailed energy insights on the devices in their homes and businesses, or automatically notify the Company's control centers of an outage. Similarly, the Company's billing systems are designed to collect and issue bills based on monthly volumetric energy usage (i.e., how much total energy did I consume this month?), and do not have the functionality today to support TVR. The Company has also received approval to install AMI which is discussed in more detail in Section 6.

Customer portals

- Interconnection portals. The Company has a series of related Salesforce-based customer portals (at different states of maturity) enabling trade partners (e.g., electricians, plumbers, solar installers) to login and submit application materials, check statuses, receive automated email notifications, and correspond directly with employees regarding generation, storage, electric load, and gas connection requests as well as EV incentive program requests. Once a trade partner has submitted an application, the Company's billing customers (and other application stakeholders identified by the trade partner) are able to check statuses, receive automated email notifications, and use the Contact Us form to also correspond with employees about their applications as well as DER billing and incentive program requests after the connection is completed.
- Demand side management program management. Today, the Company utilizes a Demand Side Management system called InDemand to fulfill and deliver on customer requests for clean energy products and programs. This program was originally designed to support implementation of the Company's Energy Efficiency programs. However, with the rapid growth of clean energy, this platform has become antiquated and led to inefficient manual processes, lack of data uniformity and poor customer/trade partner/employee experience. A new platform (Clean Energy 2.0) is in development to greatly improve upon this portal, which will be described in Section 6.

Data

Data is the foundation of much of what the Company does as a utility, including planning, network management and operations. Maintaining and improving interoperability among different software systems to allow diverse datasets to be merged or aggregated in meaningful ways can support better customer, operations, and business outcomes. Historically, the Company's network operation, planning, and customer empowerment have been somewhat limited by data availability. This is changing considerably with, for instance, expansion of feeder monitoring, deployment of ADMS, and new advanced metering systems. The ability to leverage data as a resource to plan and operate a more intelligent grid and create meaningful and valuable opportunities for customers requires continuous investment in data management.

Asset planning, management, and work execution

System planning leverages the CYMDIST software which is used to model and run analyses on the Company's distribution system and the Siemens PTI PSS/e loadflow program. ASPEN RDB for Distribution Equipment serves as the centralized repository to record electric distribution device settings information. For asset management, Geographic Information System (GIS) is a technology that combines the power of maps with the function of a database. The Company utilizes GIS as its authoritative source for distribution asset information and as designed network configuration (i.e., "connected model"). GIS information is utilized in several business processes including distribution system project design, load flow modeling, outage management, and analysis models. Cascade is the software application that serves as the asset repository for substation equipment. Maintenance and inspection records are stored in Cascade, which drives the condition-based maintenance programs for substation equipment. STORMS is the foundational work order creation and management system employed by all Electric Line (Tx and Dx) business functions. The platform accepts data inputs from a multitude of different business and IT-owned systems today and transforms this information into dispatchable work orders that field crews use to complete job tasks, ranging from repairing a leaning pole to triggering the design process for replacing an entire feeder.

Security

The protection of both physical and cyber assets is fundamentally important for the Company with its ownership and management of Critical Energy Infrastructure. Examples of existing physical security measures include fences and security cameras, and cybersecurity measures include ubiquitous two factor authentication, next generation firewalls, data loss prevention and intrusion detection. With the shift to digitalization and the integration of telecommunications-based systems, security becomes increasingly important, and these demands continue to grow.

Section 5

5- and 10-Year Electric Demand Forecast

This section describes the methodology and details of the 5- and 10-year electric demand forecasts that underlie the proposed Future Grid infrastructure investments.

Key Take-Aways

- The Company uses a robust approach, based on industry best practice, to develop demand forecasts that consider underlying economic and demographic drivers of customer demand as well as increasingly important clean energy policy drivers—namely, energy efficiency, demand response, solar PV, energy storage, EV charging, and heat electrification.
- The 5- and 10-year demand forecasts align with the Commonwealth's ambitious clean energy and GHG emission reductions goals for 2030, modeling acceleration in adoption of EVs and EHPs and expansion of solar, energy storage, and other DER.
- The Company and its customers face an inflection point where 15 years of relatively flat demand will give way to annual peak load that is expected to grow by 7% by 2029 and 21% by 2034 relative to 2022 levels—even after accounting for the offsetting impact of energy efficiency, demand response, solar PV, and energy storage—as policy-driven heat and transportation electrification accelerate in the Commonwealth.
- Given the critical role that the demand forecast plays in determining the need for infrastructure investments in the Future Grid Plan, the Company routinely benchmarks its forecast by comparing to independent forecasts from peer EDCs and the Commonwealth. The Company also engaged a leading expert from The Brattle Group to provide an external assessment of the demand forecast methodology for the Future Grid Plan. Both of these assessments corroborate the Company's demand forecast.

5.0 5- and 10-Year Electric Demand Forecast

What is demand forecasting and why is it important?

Electric demand or load is how much electrical power is consumed by end-users at a specific point in time. Demand varies throughout the day and year and is typically higher when it is very hot or very cold and heating/cooling needs are highest. Peak demand, the hour with the highest demand over the year, is critical for planning electric network infrastructure because the network must be able to serve peak demand.

Forecasting future peak demand is important because constructing electric network infrastructure has long lead times and electrical network assets are long-lived. The demand forecast ensures that the Company can build infrastructure at the right place and at the right time to reliably provide customers with the power they need.

The demand forecast is an important tool to meet the Commonwealth's climate goals. The substantial beneficial electrification of heating and transportation that are part of the Commonwealth's pathway to achieving net zero will increase demand and therefore the need for infrastructure. The forecast is critical to enabling this transition by informing the Company about when and where the infrastructure is needed to support the clean energy transition. The demand forecast also includes projecting the impacts of clean energy policies and programs that offset demand growth, such as DR, so that the Company is able to locate and size infrastructure investments appropriately after impacts of demand reduction programs are accounted for.

5.1 5- and 10-Year Electric Demand Forecast at the EDC Territory Level

Summary: The demand forecast demonstrates that the Company is at an inflection point on the path to decarbonization in how customers use electricity. Despite underlying economic growth, peak demand for electricity has been essentially flat over the last 15 years because growth was offset by EE, DR, and solar PV (see Exhibit 5.1), supported by the Company's nation-leading programs. While these programs will continue to reduce demand relative to what it would otherwise be,[1] achieving a decarbonized economy, consistent with the Commonwealth's goals, means that beneficial electrification of heat and transportation must immediately increase. Beneficial electrification causes the demand forecast to show increased load over the 10-year forecast horizon (see Exhibit 5.5 below) and more than doubling in demand by 2050 (See Section 8 for a discussion of the demand assessment from 2035-2050).

Methodology overview: Below is a brief overview of the Company's demand forecasting methodology. More details can be found in the Appendix.

1. Weather design criteria: In the first step, the Company analyzes historical weather to determine the weather design criteria. Electric infrastructure needs to be able to reliably provide power in the most extreme conditions – the hottest days in the summer and the coldest days in the winter. The peak demand forecast is therefore calibrated to peaks that occur under extreme temperatures – the 90th percentile. For the summer, this means a design temperature such that the hottest day of the year will exceed it only once every 10 years, on average. In the winter, the coldest day of the year will be colder than the design temperature only once every ten years, on average.

2. Disaggregation: In this step, the Company disaggregates the historical demand data to separate out historical baseload demand and the historical impact of DERs. Historical demand that the Company has observed has been embedded in its underlying customer energy requirements

[1] See Section 6 for a discussion of how an increased focus on DR can help reduce, but not eliminate, the need for new infrastructure investment.

(referred to here as baseload), as well as the effects of EE, DR, photovoltaics (PV), and energy storage (ES), electric vehicles (EV), and electrification of heat (EH) -- collectively referred to here as DERs. Over the last 15 years, net demand (i.e., demand that is actually measured) has been flat to declining because the impacts of EE, DR, and PV have offset underlying customer demand growth from new customers and economic growth. If only net demand was modeled, as opposed to the separate effects of baseload and DERs, the Company's modeling would miss the nuances of the effects of baseload and the various DERs, and the Company would be less able to project the effects on net demand of changes in customer growth or DER penetration going forward. Instead, the Company disaggregates historical baseload and DERs and forecasts them each separately, then recombines them to get a single net load forecast.

3. Baseload econometric forecast: The underlying customer energy requirements, or baseload, are projected using an econometric forecast. This forecast is developed by looking at the historical trends and relationships between historical baseload and macro-economic, demographic, and pricing variables. These historic relationships are then used in conjunction with expectations for future changes (e.g., projected customer growth, expected demographic changes) to forecast future demand. Customer counts and use-per-customer are forecasted separately to disaggregate their effects – for example residential customer counts may increase due to new construction projects, but residential use-per-customer may be flat-to-declining due to energy efficiency. Forecasting of customer count and use-per-customer is done separately for residential, commercial, and industrial customers since each sectors' growth rates are driven by different factors and may be best reflected by different macroeconomics/demographics. For example, residential customer count is most tightly correlated with the number of households, while commercial use-per-customer is best correlated with gross state product, reflecting overall economic strength. The Company obtains macro-economic historical and forecast data from Moody's Analytics at the county and metro-area level.

4. DER forecasts: Each DER is independently forecasted. In the short-run, forecasts for DERs are consistent with current trends, policies, and programs. However, the outer-year DER forecasts align with the Commonwealth's relevant clean energy goals. The DER forecasts align with the preferred State decarbonization pathway, which the Company models based on the "All Options" scenario from the Commonwealth's CECP for DG and the "Phased" scenario for EH. See Section 5.1.4 - 5.1.7 for further discussion of forecasting for each of the DERs.

5. System peak forecast: The econometric forecast and DER forecasts are combined into the aggregate demand to create a final system peak forecast of total net load.

6. Spatial allocation: In addition to the demand forecast at the system level, the Company also develops forecasts at a more granular level. The econometric and DER forecasts are independently allocated to different planning areas based on local census and parcel-level characteristics. Each DER is allocated independently at this granular level since DER penetration is not assumed to be uniform across the Company's service territory. For example, large PV installations may be more likely to be developed in areas where land is more plentiful and less expensive and closer to interconnection points. For presentation and reporting purposes in the ESMP, the granular forecasts are aggregated to the sub-region level and discussed further below (beginning in Section 5.2).

7. Validation: The Company benchmarks its forecast against the CECP. The underlying assumptions for the DERs in the Company forecast align with the targets in the CECP "Phased" pathway (see Sections 5.1.4 - 5.1.7 for additional detail). The CECP Pathways Analysis[2] expects approximately 10% growth in peak demand from 2020 – 2030 which matches the expected growth in the Company's forecast over the same period, validating the Company's work aligning with the CECP.

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[2] CECP, June 2022, page 72 Pathways Analysis: Electrification and Electric System Needs

Comparison with Eversource and Unitil: The electric distribution companies (EDCs) in Massachusetts made up of 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 methodology employed by each individual EDC are aligned for the baseload econometric forecast, design weather conditions, and DERs. The EDCs utilize more than a decade of historical weather data (region dependent) to develop the design weather – the 90th percentile – and use it as the primary planning case. Eversource and National Grid utilize an econometric forecast model for the baseload while Until projects recent historic growth forward (before incorporating the impact of solar, storage, DR, EHPs, and EVs). The EDCs then incorporate adjustments for DER. Each DER is independently forecasted considering their current market trend, policies, programs, and State decarbonization pathways. The EDCs all produce the forecasts at the jurisdiction level and allocate to more granular geospatial areas based on regional characteristics.

The amount and rate of deployment of total installed solar capacity is specific to each utility and described further in Section 5.1.5. Eversource and National Grid use the same software to predict parcel wise allocation of ground mounted solar installations. The underlying parcel and land use data and method of simulating region-specific PV adoption is the same; based on land parcel availability and profitability analysis. Unitil forecasts future solar capacity based on historical trends.

Electrification in the transportation and buildings sector, in the form of EVs and electric heating (EHPs), are anticipated to be load drivers but are still relatively new technologies. Existing adoption of EVs and EHPs show very low penetration across the Commonwealth, as discussed for each sub-region in Section 4 above. The EDC's near-term adoption estimates are based on a combination of historical adoption, current market outlook, company plans and policy direction. Eversource and National Grid model granular spatial allocation using aggregated household characteristics, socioeconomic information, and travel patterns. Eversource leverages traffic data from the same data vendor as the Massachusetts Department of Transportation ("MA-DOT"). National Grid applies data for commuting demands from the Census Bureau. Unitil utilizes ISO, EEI assumptions, census data and registered vehicle data to develop a projection for EV adoption and load forecast.

Sections 5.1.1 - 5.1.7 give additional detail on the components for the forecast at the jurisdictional level (i.e., for the Company's Massachusetts service territory, including the Massachusetts Electric Company and Nantucket Electric Company level combined). Sections 5.2 - 5.7 dive into the regional outlooks. More detailed discussions are provided in the Appendix.

5.1.1 Aggregate Demand – Summer and Winter

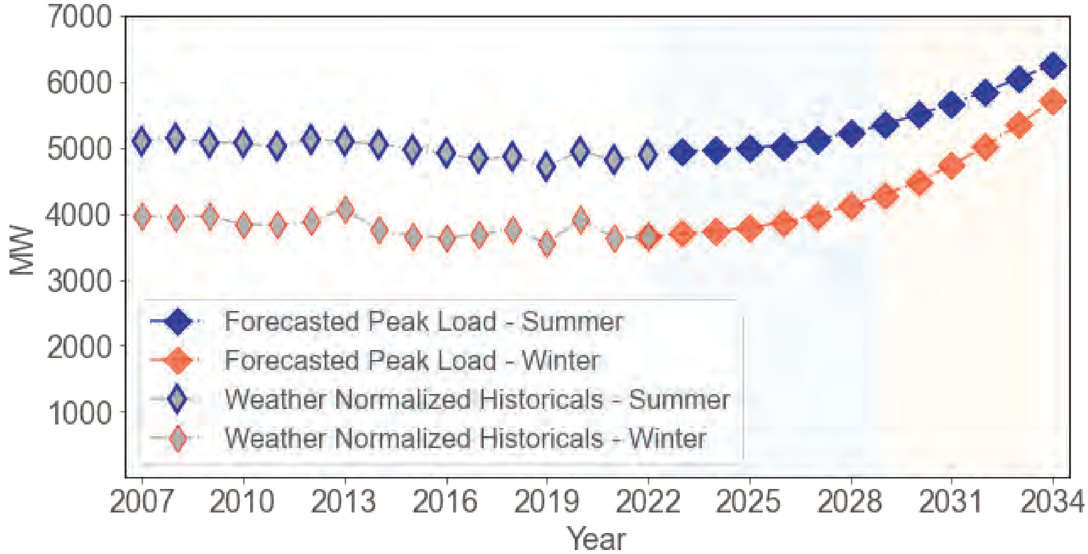
Aggregate demand refers to the actual net demand on the system (i.e., the sum of the baseload and DERs, not disaggregated). This aggregate demand is what the infrastructure must be sized to meet. The annual demand peak has historically occurred in the summer season, typically during a very hot summer weekday afternoon. In recent years, the peak hour has gradually shifted to early evening as increasing penetration of DG (i.e., PV) has begun offsetting the load earlier in the afternoon and becomes less available or unavailable later in the day towards sunset.

Exhibit 5.1 shows the historical and aggregate peak demand for the summer and winter. Aggregate peak demand has remained relatively flat for roughly the last 15 years despite increases in baseload, since that baseline growth has been offset by increases in EE, PV, and DR. Over the next 10 years, however aggregate demand is projected to begin to increase, at a CAGR of 1.3% through 2029 and 2.1%[3] through 2034. As shown in Exhibit 5.1 the winter peak is increasing at a faster rate than the summer peak due to growth of EH. The system remains summer peaking through the forecast period (2025-2034), so EH does not yet have a meaningful impact on the peak load that

[3] The starting year is 2022 for all CAGR calculations in Section 5.

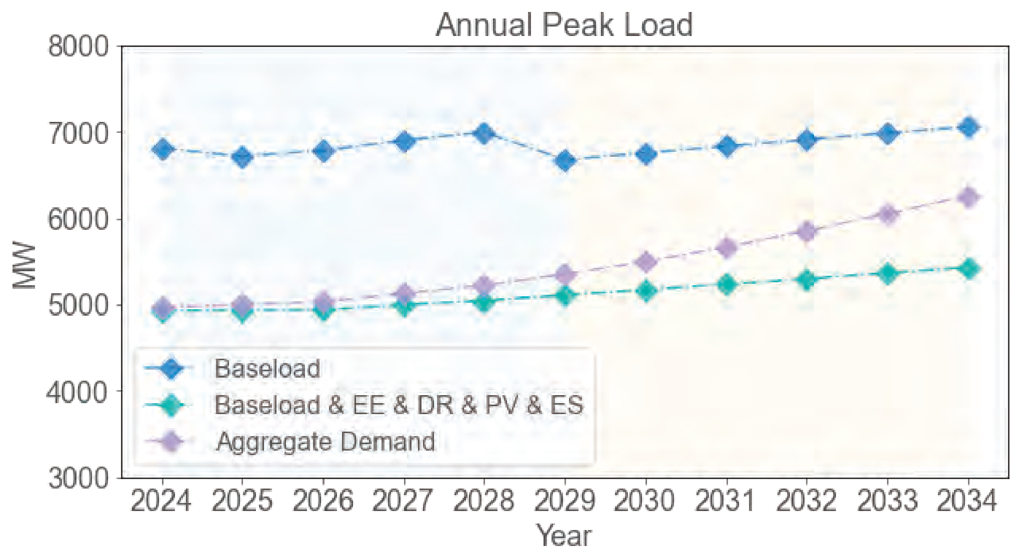
drives electricity network investment planning. However, the system is projected to switch to winter peaking during the demand assessment period, which is further discussed in Section 8.

Exhibit 5.1: Historical and Forecasted Aggregate Peak Demand for Summer and Winter



The projected demand growth is primarily due to projected increased beneficial electrification from EVs in accordance with the State's climate goals, as well as cumulative EE savings that are beginning to grow at a slower rate as incremental EE savings become harder to come by due to long-term program success. Moreover, while PV adoption continues to grow, the peak hour shifts later in the day when PV has less of an impact on peak demand. Exhibit 5.2 illustrates how the saturation of EE and the shift to a later peak hour when PV has limited impact mean that DERs (excluding EV and EH) are not projected to offset the underlying growth in electricity demand in the future. To see this, compare the roughly parallel tracks of the top and bottom lines, (where the kink in the baseload demand is from PV and EV charging load pushing the peak hour later in the day), which demonstrates that EE, DR, PV, and ES are not offsetting increases in baseload. In addition, comparing the middle line in the exhibit to the bottom line shows the substantial uptick in demand driven by EVs.

Exhibit 5.2: Annual Peak Load by Components



The waterfall charts in Exhibits 5.3-5.5 show the breakdown of aggregate demand and provide a snapshot of each component's impact at year 2022, 2029, and 2034, respectively. Despite the slowing growth of cumulative EE savings, EE remains by far the DER with the biggest impact on aggregate demand through this time horizon. The impact of EVs grows rapidly during this time period before becoming the second largest factor modifying baseload demand by 2029. EH also has some impact on summer peak demand from EHPs used for summer cooling, including for customers who would not otherwise have had air conditioning (or have had as much)

Exhibit 5.3: Annual Peak Load by Components in 2022

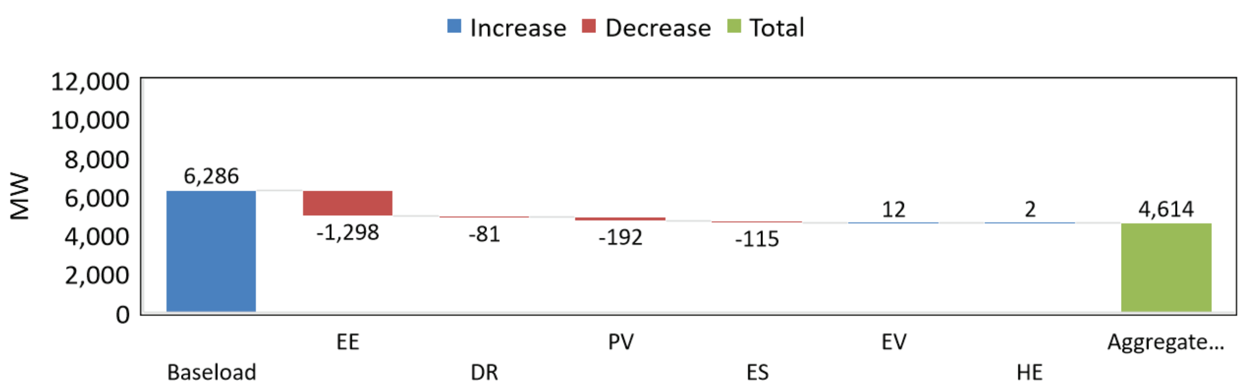


Exhibit 5.4: Annual Peak Load by Components in 2029

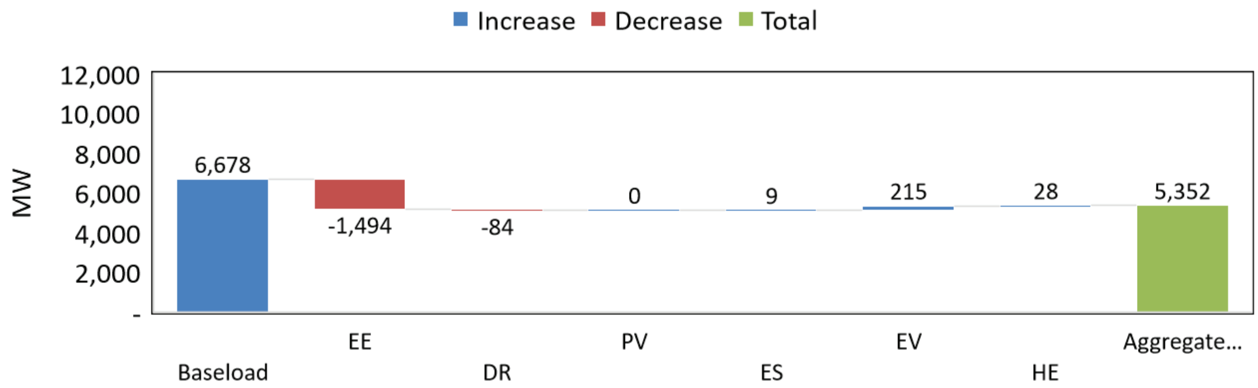
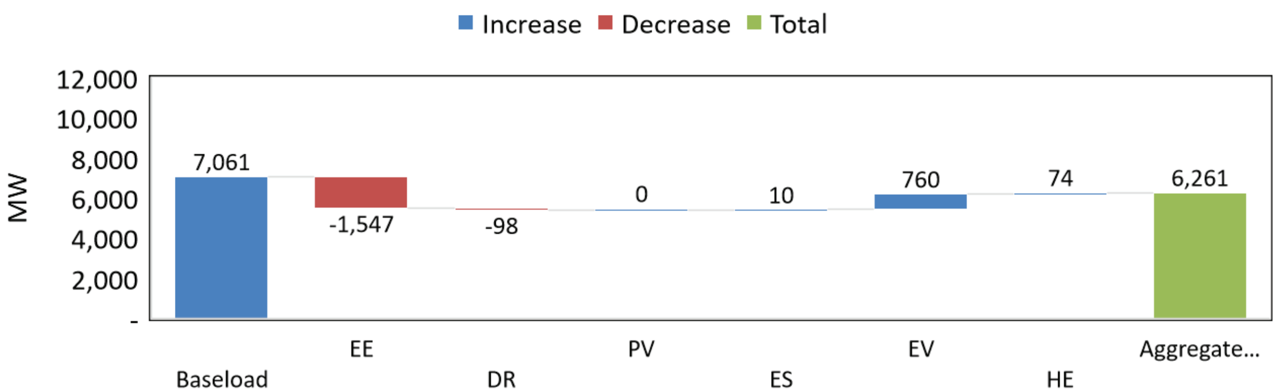


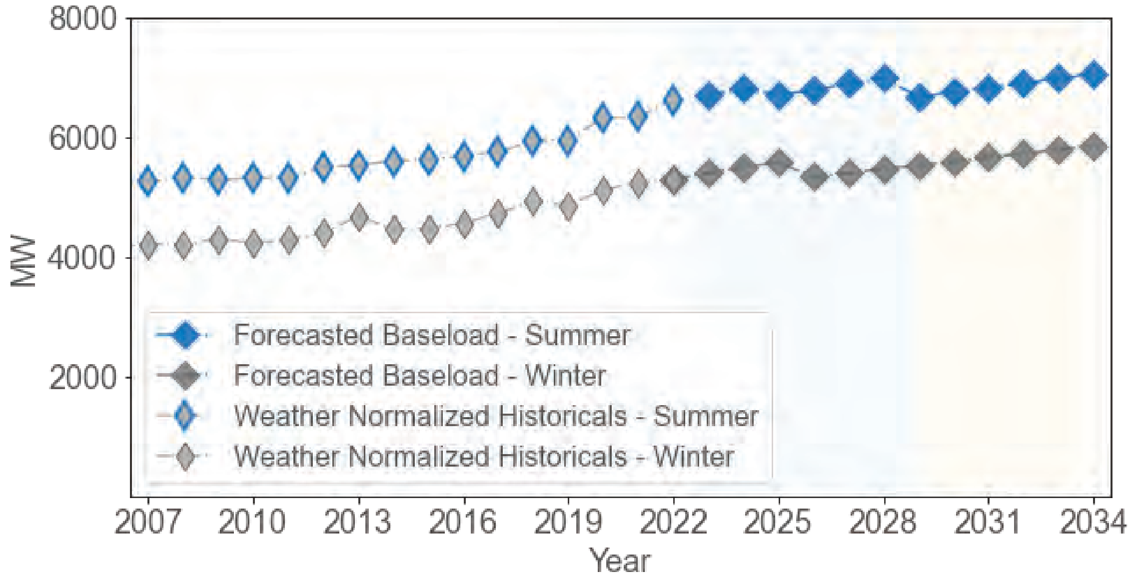
Exhibit 5.5: Annual Peak Load by Components in 2034



5.1.2 Weather Normalized Econometric Forecast

Exhibit 5.6 presents the historical and forecasted baseload at the hour of the peak demand. The peak hour is expected to shift from late afternoon (17:00-18:00) to the evening due to the impact of PVs. This shifting of the peak hour shows up as the two step-downs of the forecasted summer baseload in the exhibit. Comparing the baseload at the same hour over years, the baseload is forecasted to grow at a CAGR of 1.3% over the forecast horizon primarily driven by the economic outlook. Note that the baseload at the new evening peak hour will continue to be lower than forecasted baseload at the current peak hour in the afternoon, but because afternoon demand is partially offset by PV, aggregate demand will be highest in the evening.

Exhibit 5.6: Historical and Forecasted Baseload



5.1.3 Large Load (Step/Spot Load)

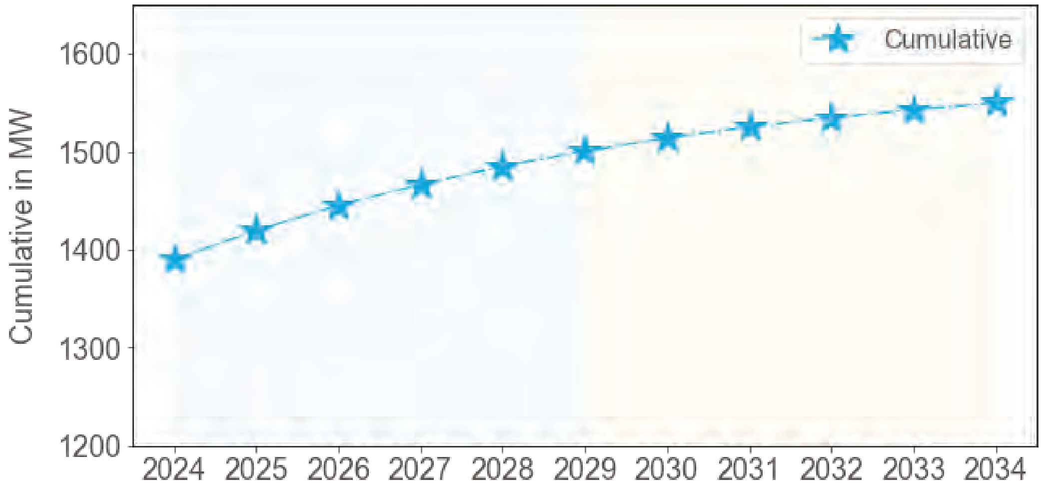
The demand forecast shows long-term trends in baseline demand growth from underlying economic activity and DER dynamics. Some of those demand drivers are service-territory-wide (e.g., the energy savings from widespread residential EE measures) and others are specific large loads located in one particular community (e.g., a new factory or data center). The Company does not forecast specific large loads. Rather, any new infrastructure needed to serve large loads is captured through the Company's interconnection and distribution planning processes.

5.1.4 Energy Efficiency

The Company has operated EE programs in Massachusetts for many years, contributing to Massachusetts being recognized as a national leader in implementing high-quality EE programs.[4] The Company will continue to operate its nation leading EE programs for the foreseeable future with support from State policies and funding. In the short term (i.e., through year 2024), EE targets in the forecast are based on the Company's three-year EE plan approved by the Department. Beyond the year 2024, the cumulative value of persistent EE savings is still expected to continue to grow but at a slower rate each year reflecting market saturation and uncertainties in policies and funding as shown in Exhibit 5.7.

[4] https://www.aceee.org/state-policy/scorecard

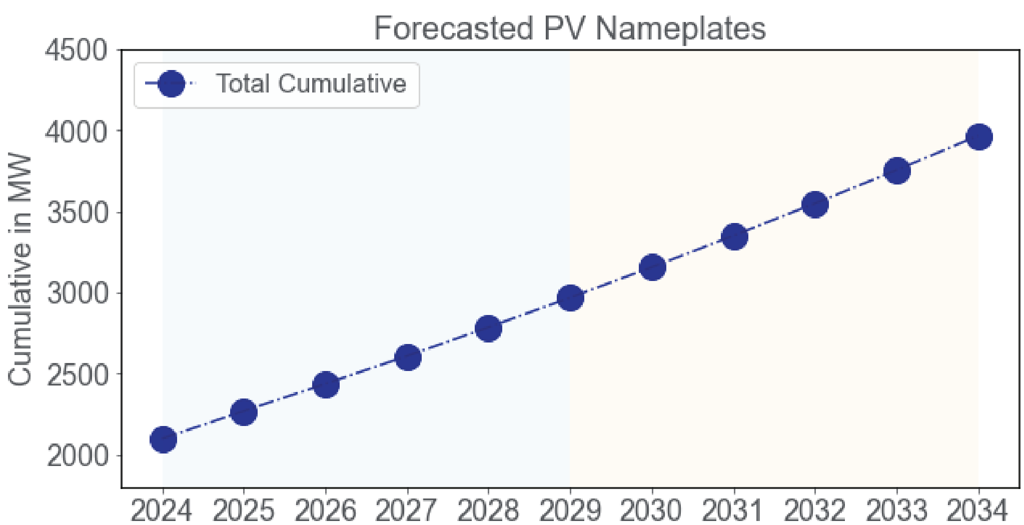
Exhibit 5.7: Forecasted and Cumulative EE Savings



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

There has been a rapid increase in the adoption of PV throughout the State. The near-term (2023-2027) predictions leveraged the information on the PV projects from the Company's interconnection queue and the insights from PV subject matter experts at the Company, and assumes the Company fills its share of the State's existing solar target of 3.2 GW[5] by mid 2020s. In the longer term, continuous growth in PV is projected to achieve the Company's share of the State policy target under the "All Options" scenario, as stated in the Commonwealth's 2050 decarbonization roadmap.[6] See Exhibit 5.8**.**

Exhibit 5.8: Forecasted PV Nameplates



[5] CECP, page 68, June 2022.
[6] *Massachusetts 2050 Decarbonization Roadmap*, December 2020.

ES deployment is still at a relatively early stage across the State. Growth has been rapid for only a few years. The forecast assumes continuous growth in ES connection to meet the Company's share of the statewide policy target of 1,000 MW by 2025.[7]

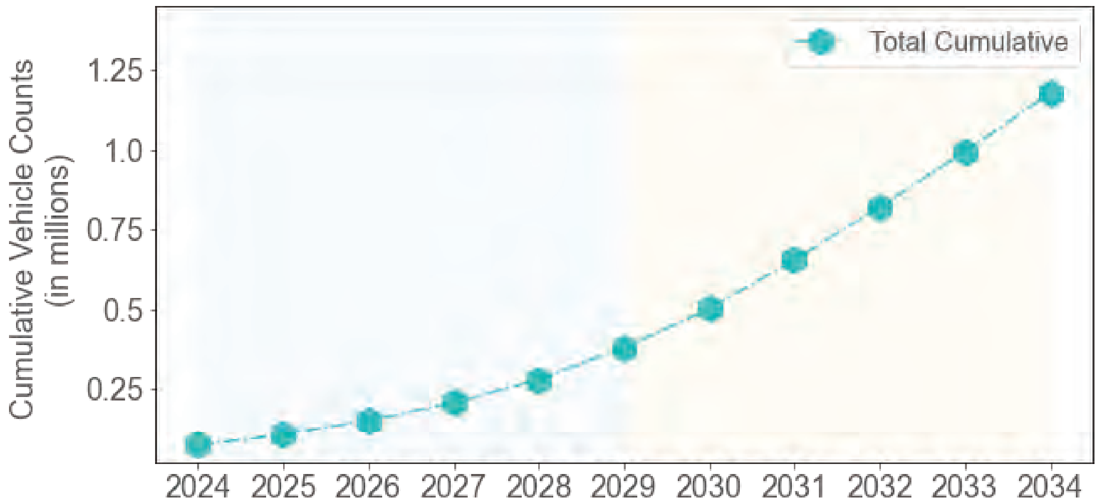
The Company currently runs a Mass Save summer DR program to reduce electricity demand during hours with high expected demand and/or reliability problems. During a DR event, customers can participate by either cutting their consumption (e.g., turning down/off their air conditioners, not charging their EV) or by supplying energy (e.g., by turning on a generator or discharging a battery to supply their demand). The Company offers various ways (e.g., thermostat controls, batteries, and programs to encourage C&I customers to fallback to alternative generators) for customers to participate. As of 2022, it is estimated that the Company's DR program helped reduce the peak by about 1.3%. Through the year 2025, projected growth of the program is informed by the Program Administrator. Beyond that and through the forecast horizon, a similar incremental growth is assumed, leading to growth of about 60% by 2034 compared to 2022.

5.1.6 Electric Vehicles

The EV forecast includes both plug-in hybrid electric vehicles (PHEVs) and battery-only electric vehicles (BEVs) since they both impact electric demand. Light-duty EV (LDEV) adoption is modeled based on the relevant policy adopted by Massachusetts, specifically the California's Advanced Clean Car II (ACC-II) Rule.[8] This Rule requires auto manufacturers to ensure that every new light-duty car sold in the State is a zero-emission vehicle (ZEV) by 2035. This is in line with the requirement for all new passenger cars and light-duty trucks sold in Massachusetts to be zero-emission starting in 2035 that was signed into law in the 2022 climate bill, An Act Driving Clean Energy and Offshore Wind.[9] The adoptions of medium-duty EV (MDEV) and heavy- duty EV (HDEV) and E-buses (both transit and school buses) are similarly modeled based on the Commonwealth's adoption of California's Advanced Clean Trucks (ACT) Rules through 2035 [10] Exhibit 5.9 shows annual incremental and cumulative EV counts through the forecast period.

[7] https://www.mass.gov/info-details/esi-goals-storage-target, retrieved November 2022
[8] https://www.mass.gov/doc/310-cmr-740-low-emission-vehicle-regulation-amendments/download
[9] https://malegislature.gov/Laws/SessionLaws/Acts/2022/Chapter179
[10] https://www.mass.gov/doc/310-cmr-740-low-emission-vehicle-regulation-amendments/download

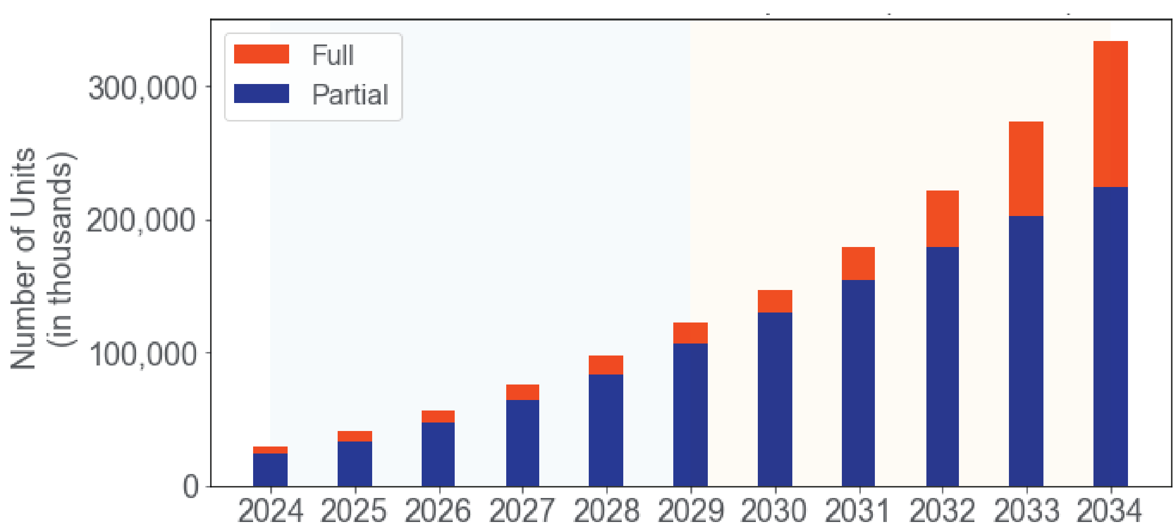
Exhibit 5.9: Forecasted Number of EVs in Operation



5.1.7 Heat Electrification

The Company's three-year plan approved by the Department guides EHP adoption projections through the year 2024. Post year 2024, the forecast follows a trajectory that meets the State's CECP "Phased" electrification scenario target by 2050, roughly aligning with interim state goals for 2030 and beyond. See Exhibit 5.10 for a graphical representation of EHP projections. Notably, all regions will remain summer peaking before 2034, hence the load impact on summer peaks from heat electrification is not meaningful compared to EV and other DERs.

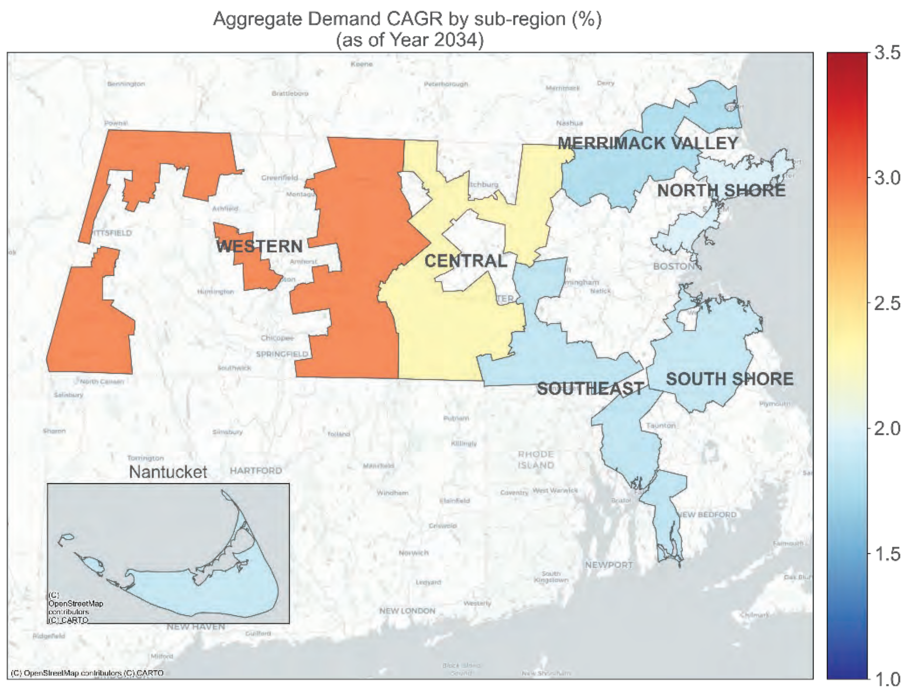
Exhibit 5.10: Forecasted Electric Heat Pump Units (Cumulative)



Starting in Section 5.2 below, the details of the Company's demand forecast are presented for the same six sub-regions described in Section 4. Exhibit 5.11 illustrates the six sub-regions and shows their CAGR through 2034. The Western sub-region overall has the most significant growth (about 2.9%) due to faster baseload growth as well as considerable EV adoption projected. The Central sub-region has about 2.3% CAGR with relatively high EV adoption and moderate baseload increase. The rapid EV growth in the Western and Central sub-regions will cause the region to switch from an afternoon to an evening peak hour earlier than other sub-regions which reduces the peak shaving potential from PV.

The North Shore sub-region is projected to experience 2% CAGR aggregate demand growth with moderate EV adoption and baseload growth while the South Shore sub-region has about 1.9% CAGR because of high growth in EV penetration, high EE savings, and moderate PV increases. Southeast and Merrimack Valley sub-regions have the lowest overall CAGR (about 1.8%) with lower EV penetration and lower baseload growth compared to other sub-regions.

Exhibit 5.11: Aggregate Demand CAGR by Sub-Region



5.2 Central Sub-Region

5.2.1 Aggregate Demand – Summer and Winter

The Central sub-region currently has the second largest electricity demand and is expected to witness steady load growth with significant DER adoptions, especially in PV.

The Central sub-region remains summer peaking through the forecast horizon. Cumulative peak load change is illustrated in Exhibits 5.12 and 5.13 below. For the 5-year horizon, peak baseload demand is expected to increase by 98 MW, which is the main driver for the peak increase. Transportation electrification has the second largest impact, adding an additional 39 MW of demand at peak. Both EE and PV are expected to result in moderate reductions to final net peak load, each reducing peak net load by 17 MW. Collectively, all of the load component variations lead to 107 MW growth in net peak demand for the Central sub-region.

For the 10-year forecast ending in 2034, baseload remains the largest driver with a 156 MW increase. EV sales are expected to rapidly ramp up, resulting in an additional 150 MW of demand on the distribution system at peak. Similar trends for EE and PV are forecasted as in the previous horizon with overall limited peak shaving impacts due to the relatively late peak hour (ending at 18:00) and thus reducing the role of PV. The final net increase to peak hour demand for the Central sub-region is projected to be about 278 MW.

Exhibit 5.12: Load Change from 2022-2029 – Central Sub-Region

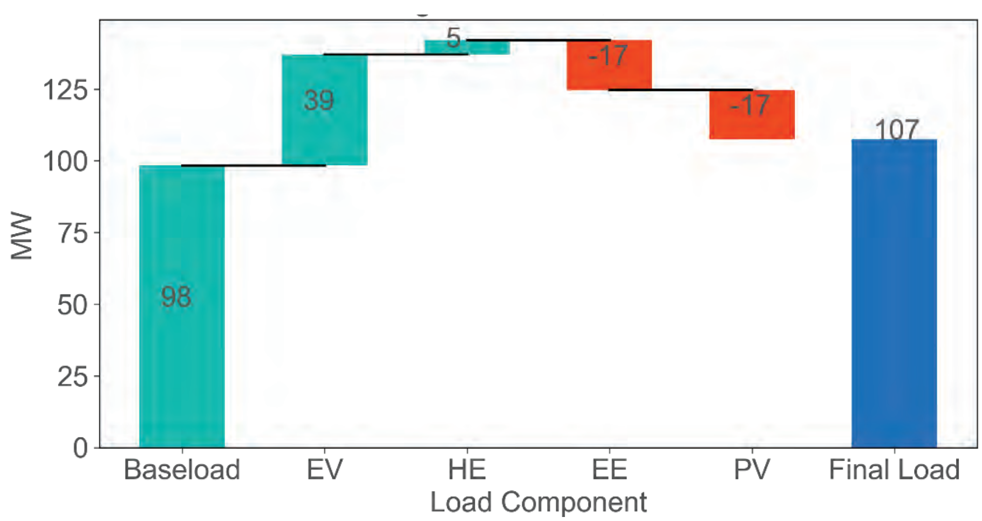
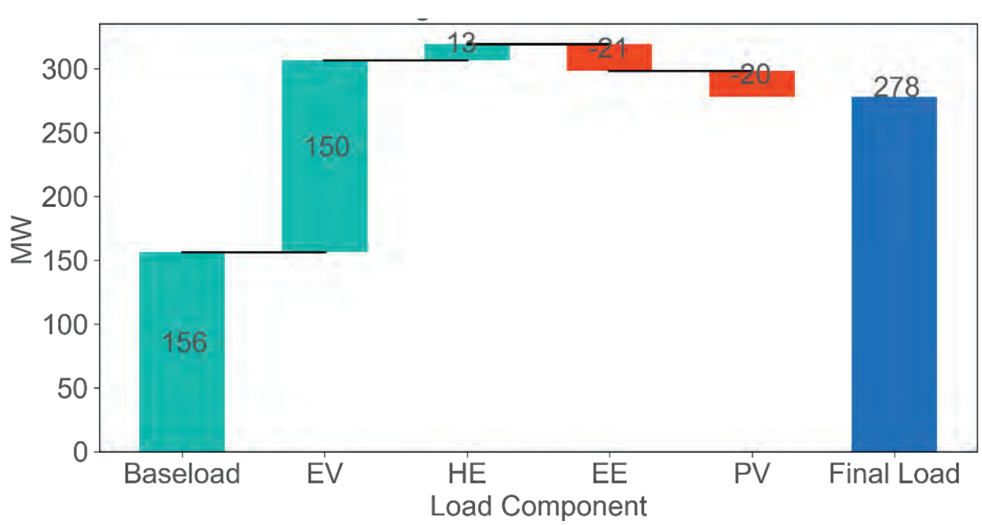


Exhibit 5.13: Load Change from 2022-2034 – Central Sub-Region



5.2.2 Weather Normalized Econometric Forecast

The baseload growth in each sub-region is derived from the Company's outlook on the ISO load zone[11] that the sub-region falls into and the sub-region's recent growth within the zone. The zonal level outlook captures the macroeconomic impacts, while within the load zone, each sub-region's recent growth reflects the variation among sub-regions in the same load zone. The Central sub-region mostly falls into the Western Central Massachusetts (WCMA) load zone. The forecast on WCMA is discussed in the Appendix the CAGR expectations for the WCMA load zone is 1.2% by 2029 and 1.1% by 2034. The Company's CAGR projections for the Central sub-region are 1.8% annual growth by 2029 and 1.6% through 2034, which are relatively high compared to other sub-regions.

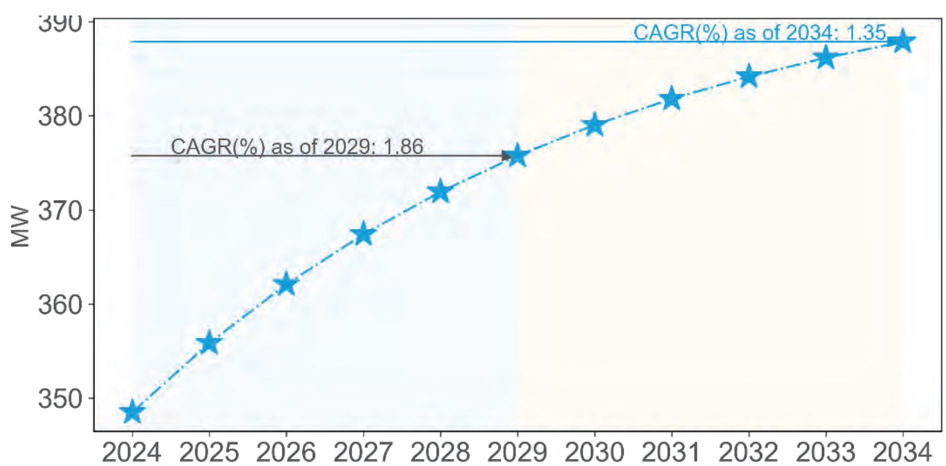
5.2.3 Large Load (Step/Spot Load)

Large load (step/spot load) impact is developed and handled in the system planning process. Please refer to Section 6 of this plan for further discussion.

5.2.4 Energy Efficiency

There are substantial EE savings projected in the Central sub-region due to its high energy consumption. The EE saving trend is depicted in Exhibit 5.14 with a CAGR of 1.9% ending in 2029 and 1.4% for the Company's 10-year horizon ending in 2034, resulting in the sub-regional EE savings increasing from 350 MW to about 390 MW.

Exhibit 5.14: EE Peak Savings – Central Sub-Region



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

With the dense population in Worcester and its surrounding medium- to high-income neighborhoods, rooftop solar is projected to grow steadily within the Central sub-region. The 5-year incremental growth is forecasted to be 66.7 MW and the10-year growth is 144.4 MW starting from the end of 2024 (Exhibit 5.15). For non-rooftop solar, this region has ample and affordable land parcels that

[11] https://www.iso-ne.com/about/key-stats/maps-and-diagrams#load-zones

meet Solar Massachusetts Renewables Target Land Use and Siting Criteria,[12] which results in a large growth margin for solar projects. Based on the current project queue information, 187.9 MW growth is expected through 2029 and 395.2 MW growth is expected by the end of 2034 (Exhibit 5.16). Combining rooftop solar with other solar, projections show total growth in solar reaching over 1000 MW. This causes the Central sub-region to become the sub-region with the largest cumulative PV capacity.

Exhibit 5.15: Rooftop Solar Adopting Trend – Central Sub-Region

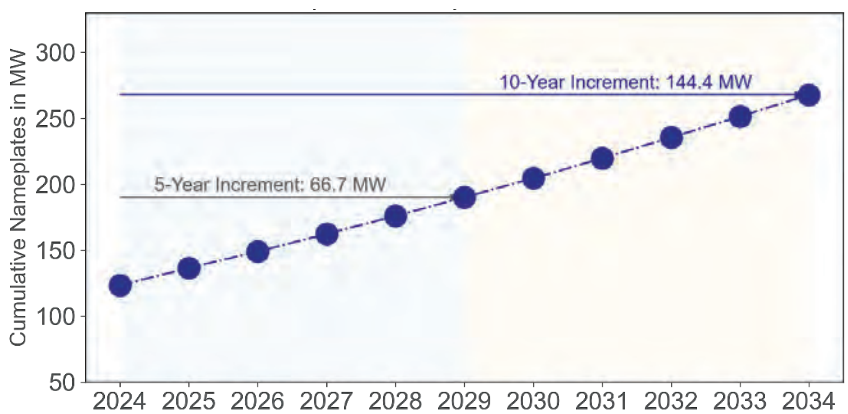
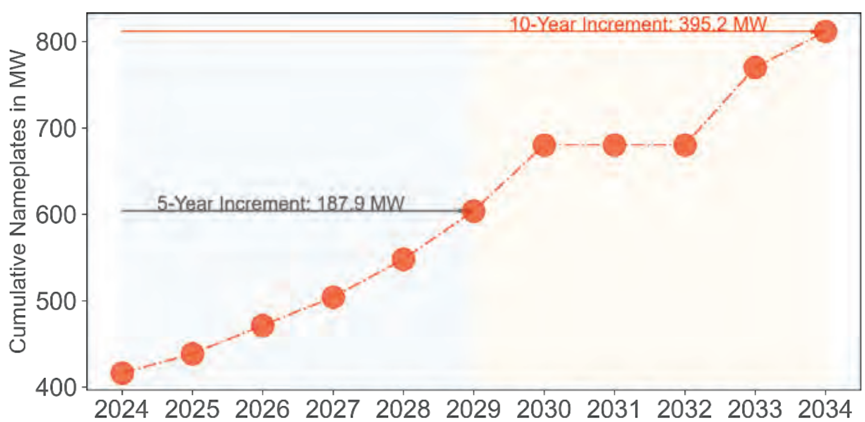


Exhibit 5.16: Non-Rooftop Solar Adopting Trend – Central Sub-Region

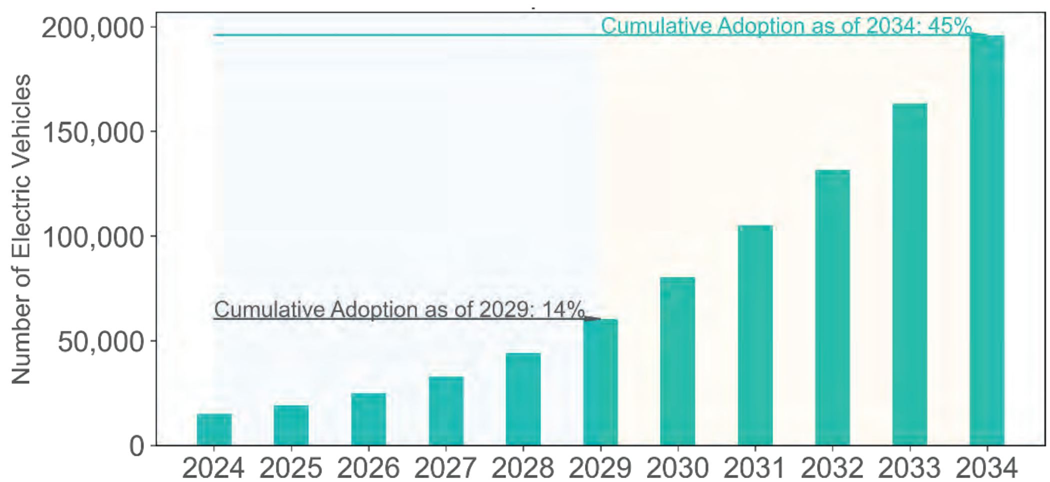


5.2.6 Electric Vehicles

As one of the most populous regions within the Company's service territory, projections for EV adoption in the Central sub-region show about 50,000 additional LDEVs to be on the road by 2029 (compared to 2024). This is about 14% of all LDEVs on the road in the service territory by the end of 2029 (Exhibit 5.17). With an accelerating growth trend, LDEVs are projected to account for about 45% of all light duty vehicles in the Central sub-region by the end of the 10-year forecast horizon.

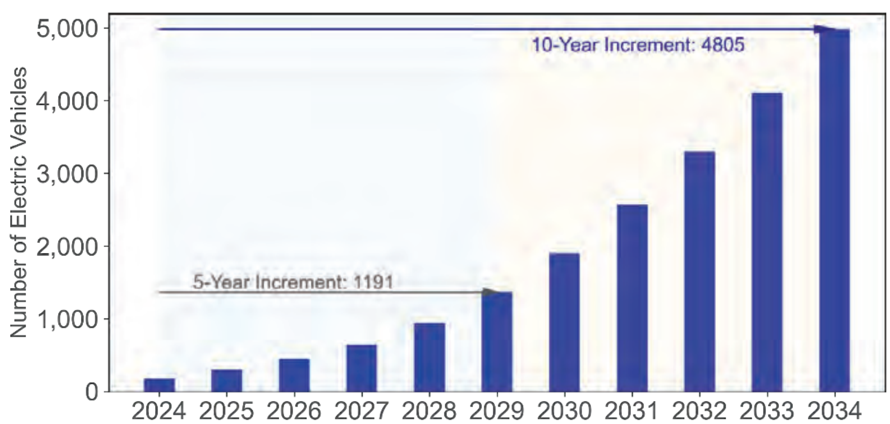
[12] https://www.mass.gov/doc/smart-land-use-and-siting-guideline-final/download

Exhibit 5.17: LDEV Adoption Trend – Central Sub-Region



The MHDEV forecast combines both medium and heavy-duty vehicles as well as buses, and the sub-regional forecast for the Central sub-region indicates about 1200 additional medium and heavy-duty vehicles will be electrified within the 5-year forecast horizon (Exhibit 5.18a). More rapid growth will take place afterwards with an additional 4800 MHDEVs in the Central sub-region by the end of 2034.

Exhibit 5.18a: MHDEV Trends – Central Sub-Region



5.2.7 Heat Electrification

There is currently a high penetration of delivered fuels (i.e., fuel oil and propane) for household heating in the Central sub-region. As a result, the Company projects relatively rapid EHP growth and a higher share of EHP adoption relative to other sub-regions. This is due to the economic and climate benefits heat electrification has for customers currently utilizing delivered fuels. Based on the Commonwealth's policy goals, EHP adoption is projected to reach 32% of all customers[13] by the end of 2029, and about 50% by the end of 2034 with about 70,000 units (including both full and

[13] This is the percentage EHPs divided by the number of electric customers forecasted at each year, including residential and commercial customers, excluding those who currently have electric heating (same for all regions).

partial) installed (Exhibit 5.18b). Because this sub-region remains summer peaking through the forecast horizon, EHPs have minimal impact on the peak forecast through 2034, however this rapid EHP adoption puts the Central region on a trajectory to become winter peaking in the later 2030's (see Section 8).

Exhibit 5.18b: Electric Heat Pump Adoption Trend – Central Sub-Region

5.3 Merrimack Valley sub-region

5.3.1 Aggregate Demand – Summer and Winter

The Merrimack Valley sub-region is forecasted to witness moderate load growth with overall moderate DER adoptions across all DER categories, as shown in Exhibits 5.19 and 5.20. The 5-year aggregate growth is 90 MW, and the 10-year growth is 236 MW.

Exhibit 5.19: Load Change from 2022-2029 – Merrimack Valley Sub-Region

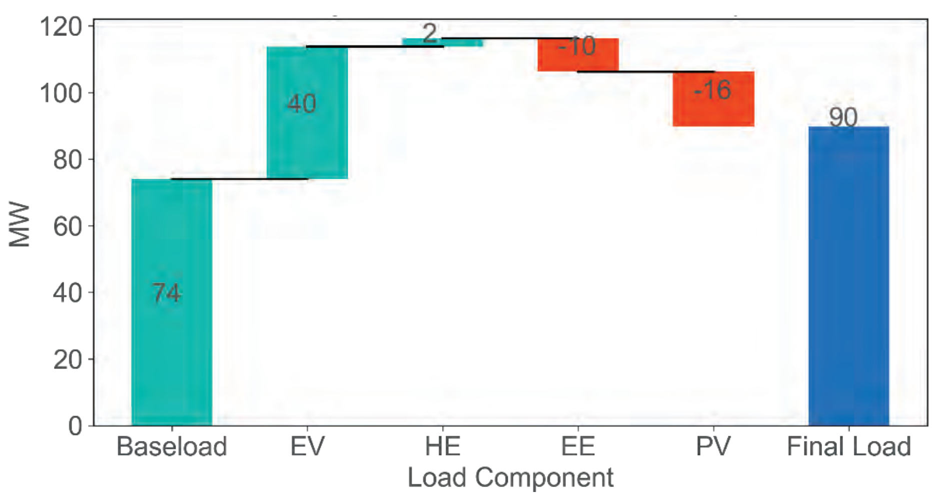
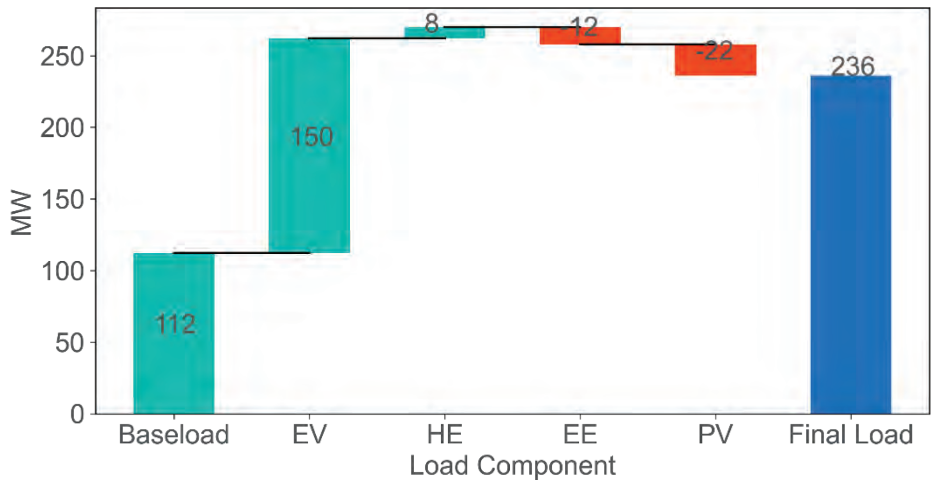


Exhibit 5.20: Load Change from 2022-2034 – Merrimack Valley Sub-Region



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5.3.2 Weather Normalized Econometric Forecast

The Merrimack Valley sub-region falls partially into the WCMA load zone and partially into the Northeastern Massachusetts (NEMA) ISO-NE load zone. The econometric forecasts for the WCMA and NEMA load zones are discussed in the Appendix. Overall, the CAGR expected for both the WCMA and NEMA load zones is 1.2% by 2029 and 1.1% by 2034. The CAGR expected for the Merrimack sub-region is an average annual growth of 1.1% by 2029 and 1.0% through 2034, a moderate increase.

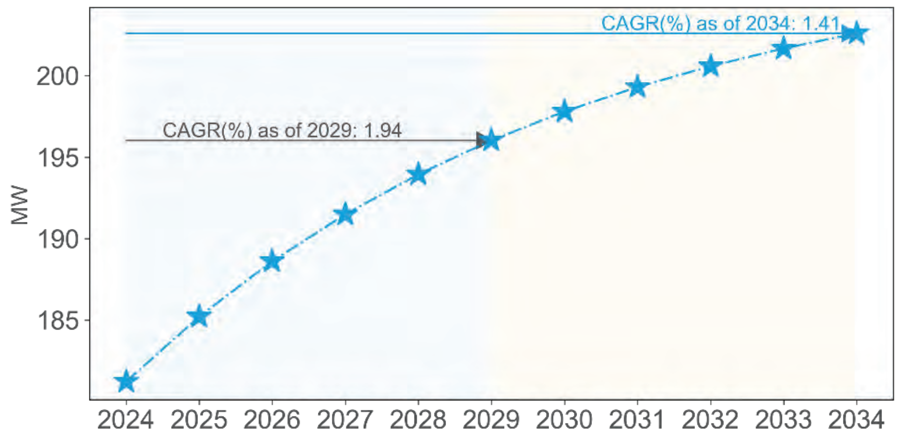
5.3.3 Large Load (Step/Spot Load)

Large load (step/spot load) impact is developed and handled in the system planning process. Please refer to Section 6 of this plan for further discussion.

5.3.4 Energy Efficiency

The Merrimack Valley's EE savings forecast exhibits a steady growth pattern. The CAGR for the Merrimack Valley EE savings is 1.9% through 2029, and, for the Company's 10-year forecast until 2034, it stands at 1.4%, reaching a cumulative peak savings of 206 MW.

Exhibit 5.21: Energy Efficiency Peak Savings – Merrimack Valley Sub-Region



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

The Merrimack Valley sub-region is anticipated to experience a consistent increase in rooftop solar installations given the large number of residential customers. The forecast shows a 5-year increment of 74 MW and a 10-year increment of 163 MW (Exhibit 5.22). Non-rooftop PV (Exhibit 5.23 has continuous growth through 2029, surpassing 170 MW in cumulative installation, and then slows down between 2029 and 2034, resulting in moderate growth.

Exhibit 5.22: Rooftop Solar Adoption Trend – Merrimack Valley Sub-Region

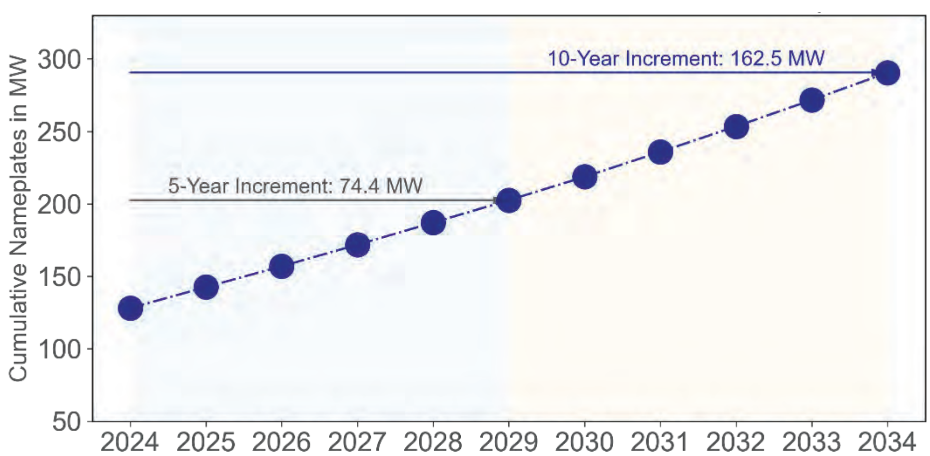
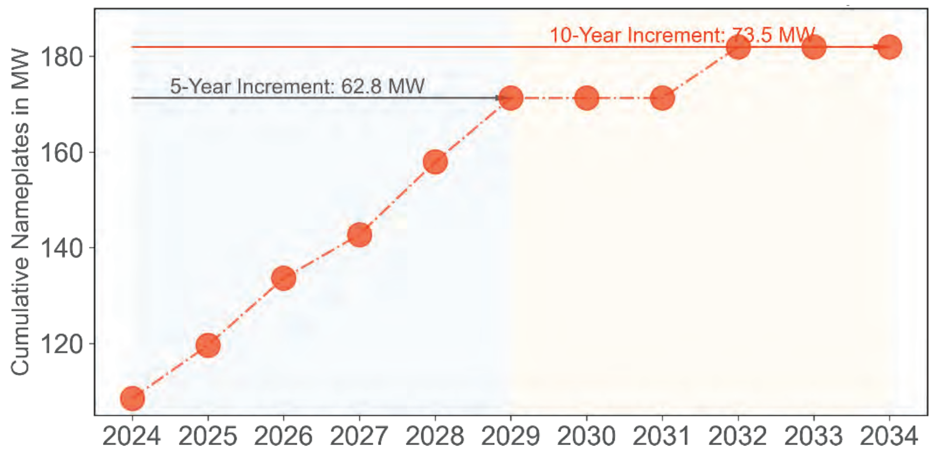


Exhibit 5.23: Non-Rooftop Solar Adoption Trend – Merrimack Valley Sub-Region



5.3.6 Electric Vehicles

Moderate LDEV penetration is expected to take place in the Merrimack Valley sub-region, with about 13% and 43% of light-duty vehicles on the road being electric by the end of 2029 and 2034, respectively, (Exhibit 5.24). The total number of LDEVs is forecasted to exceed 200,000 within the Merrimack Valley sub-region by the end of 2034. Approximately 1,000 medium and heavy-duty vehicles are expected to transition to electrification by the end of the Company's 5-year horizon (Exhibit 5.25). A more accelerated growth pattern will follow in alignment with Commonwealth policy, leading to an additional 2,500 MHDVs being electrified in the next 5 years through 2034.

Exhibit 5.24: LDEV Adoption Trend – Merrimack Valley Sub-Region

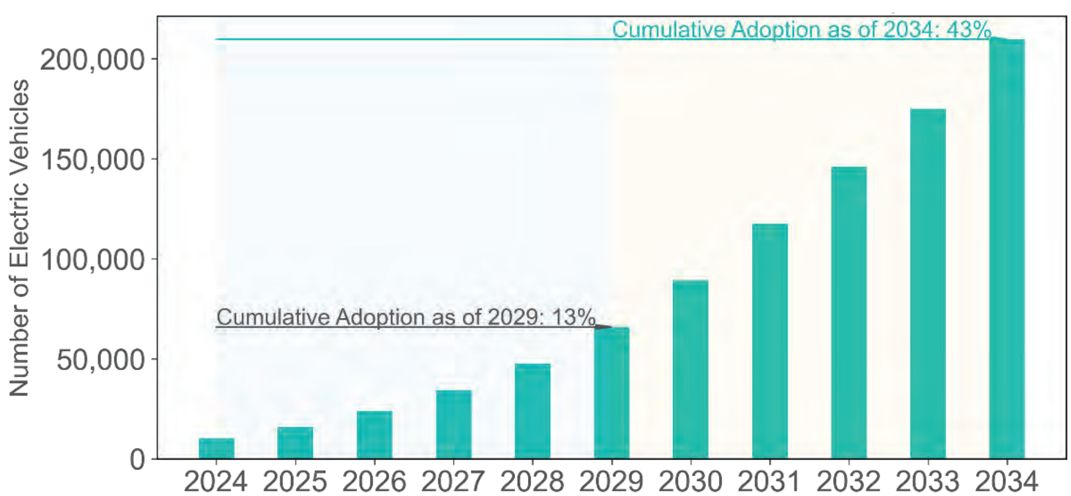
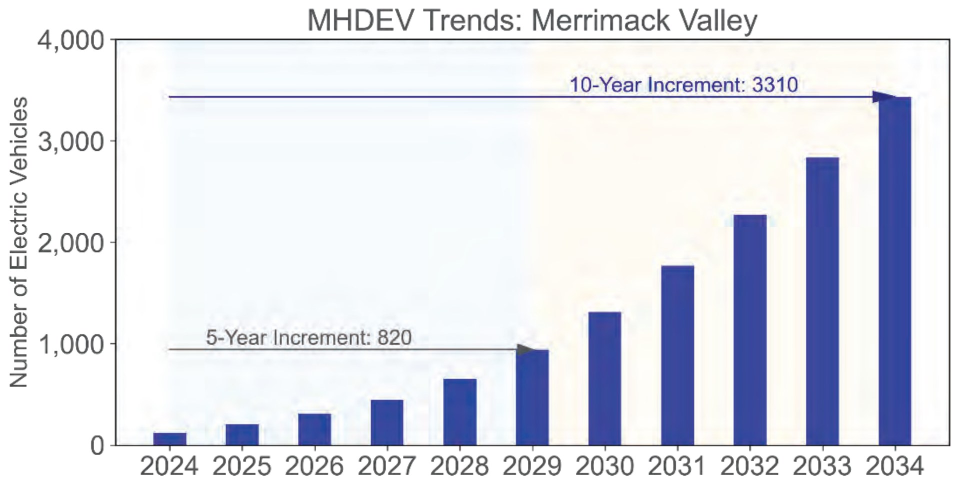


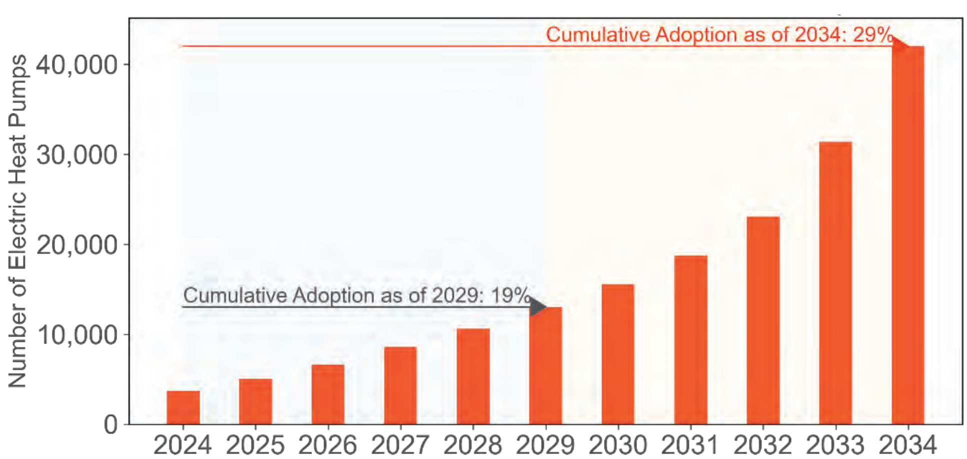
Exhibit 5.25: MHDEV Trends – Merrimack Valley Sub-Region



5.3.7 Heat Electrification

Given that the Merrimack Valley sub-region has both modest current EHP adoption as well as the lowest percentage of households utilizing delivered fuel for residential heating of any sub-region, it is expected to experience the mildest growth of heating electrification among all sub-regions, reaching about 30% EHP adoption across all electric customers by the end of 2034.

Exhibit 5.26: Electric Heat Pump Adoption Trend – Merrimack Valley Sub-Region



5.4 North Shore sub-region

5.4.1 Aggregate Demand – Summer and Winter

The North Shore sub-region is forecasted to witness moderate load growth due to a moderate EV adoption trend and low PV installation, reaching 78 MW of peak load growth through 2029, and 190 MW of aggregate peak load growth through 2034.

Exhibit 5.27: Load Change from 2022-2029 – North Shore Sub-Region

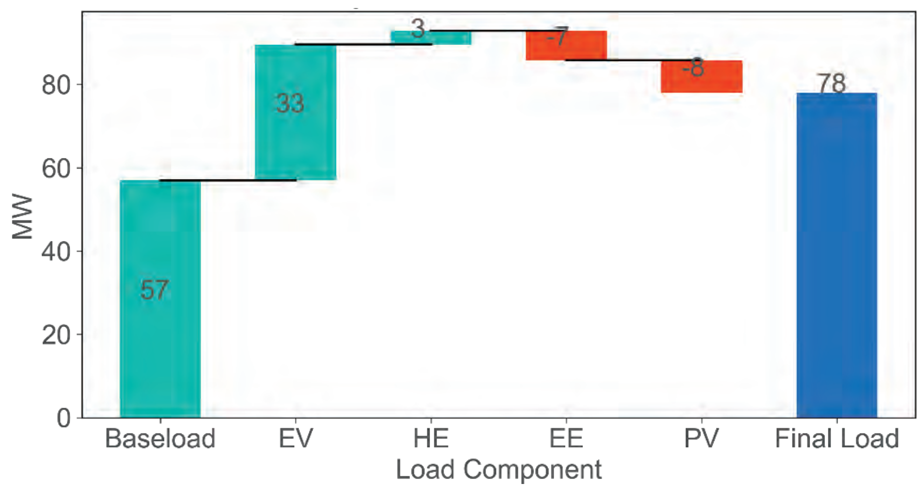
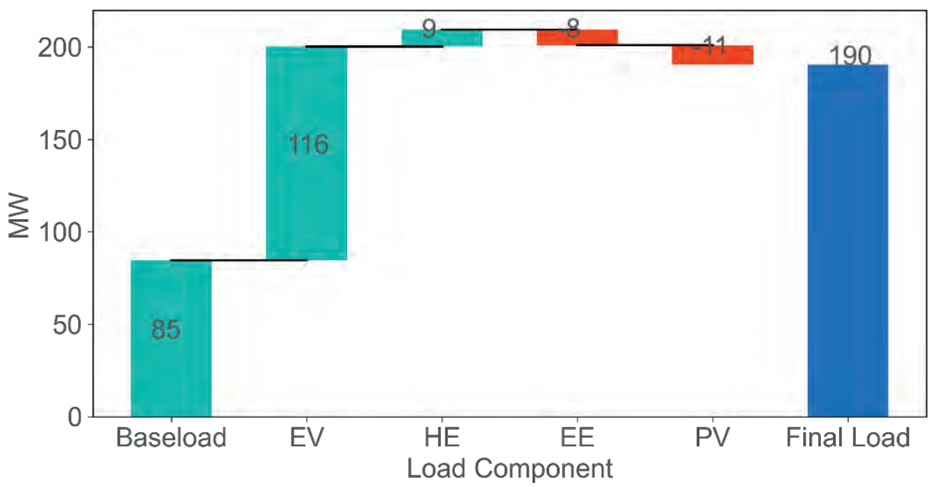


Exhibit 5.28: Load Change from 2022-2034 – North Shore Sub-Region



5.4.2 Weather Normalized Econometric Forecast

The North Shore sub-region falls entirely into the NEMA load zone. The forecast for NEMA is discussed in the Appendix. Overall, a 1.2% CAGR is expected for the NEMA load zone by 2029 and a 1.1% CAGR by 2034. The North Shore sub-region is expected to experience an average of 1.1% annual growth by 2029 and 1.0% through 2034, which is in the medium range in comparison with other sub-regions.

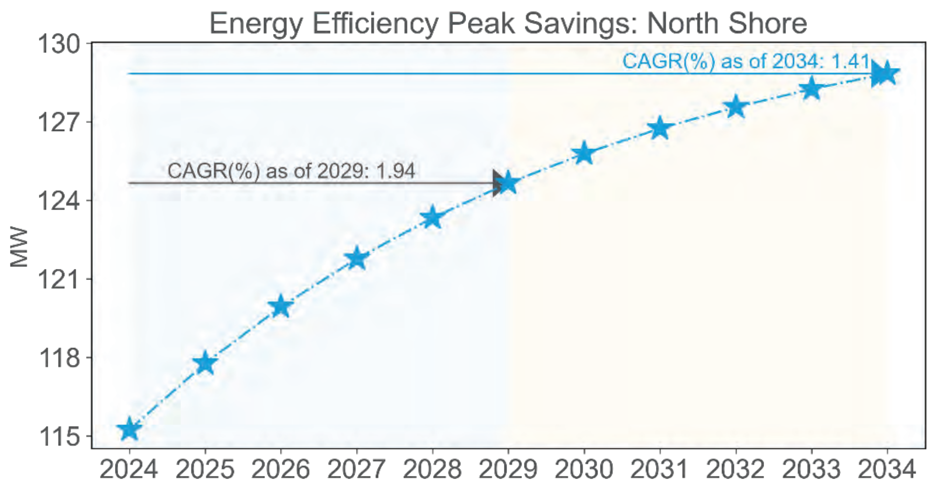
5.4.3 Large Load (Step/Spot Load)

Large load (step/spot load) impact is developed and handled in the system planning process. Please refer to Section 6 of this plan for further discussion.

5.4.4 Energy Efficiency

Like the Merrimack Valley, the North Shore's EE saving forecast follows the growth pattern associated with the Company's NEMA (ISO level) zone. The CAGR for the North Shore sub-region EE savings is 1.9% until 2029 and 1.4% through 2034 with a cumulative summer peak savings of 129 MW.

Exhibit 5.29: EE Peak Savings – North Shore Sub-Region



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

Due to the overall low availability of suitable land parcels and considerable number of residential customers, most of the PV projects that will be realized within the North Shore sub-region are rooftop solar. By the end of 2034, the North Shore sub-region is projected to have an additional 140 MW of rooftop solar and less than 10 MW of ground mounted solar.

Exhibit 5.30: Rooftop Solar Adoption Trend – North Shore Sub-Region

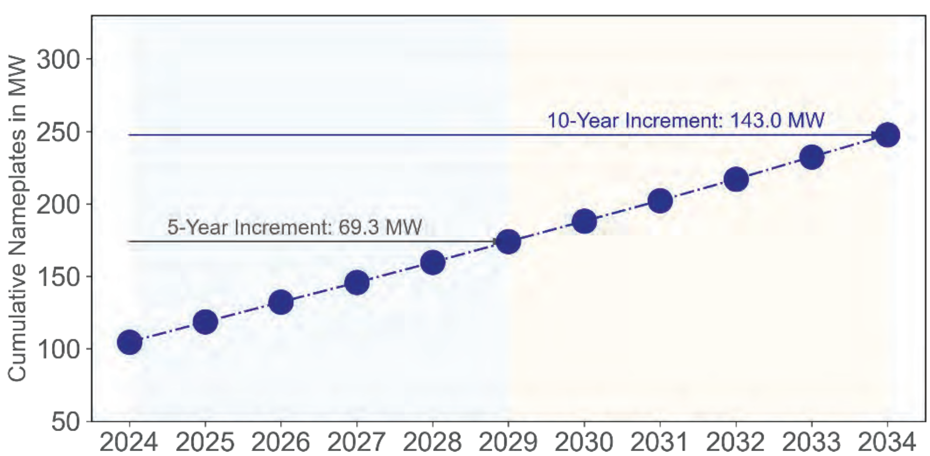
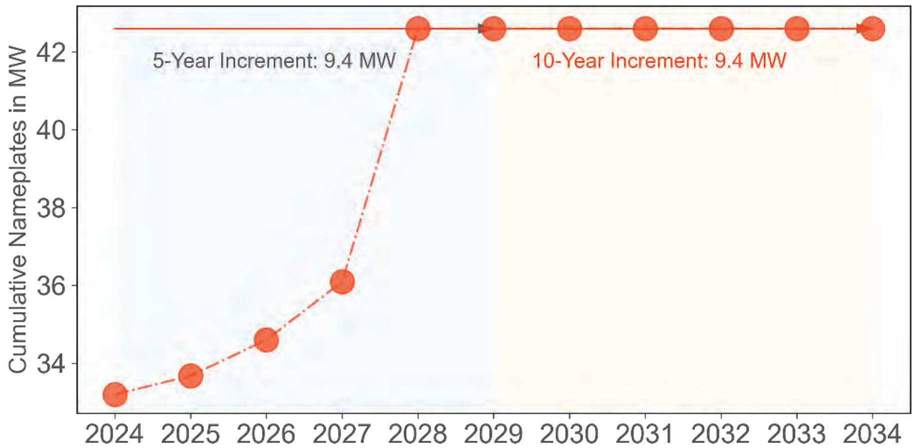


Exhibit 5.31: Non-Rooftop Solar Adoption Trend – North Shore Sub-Region



5.4.6 Electric Vehicles

EV adoption is expected to grow continuously in the North Shore sub-region, with the share of LDEVs rising to 15% before the end of 2029 and 43% by 2034. As for MHDEVs, moderate adoption is forecasted with the final number of MHDEVs for 2034 surpassing 2100.

Exhibit 5.32: LDEV Adoption Trend – North Shore Sub-Region

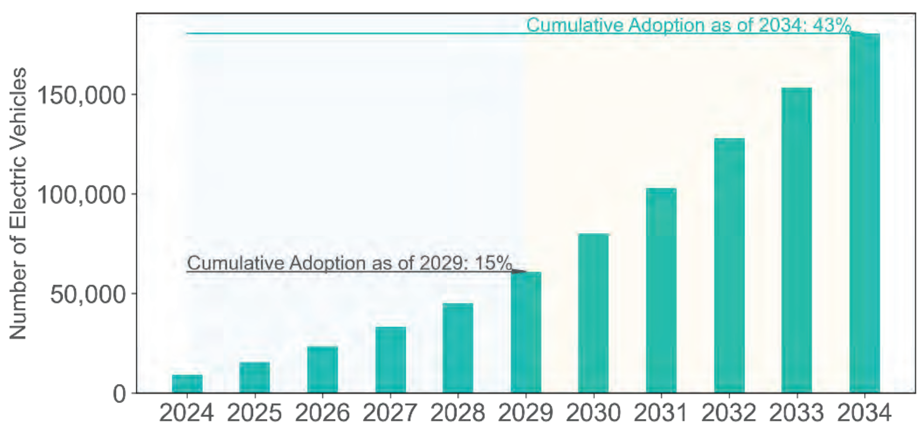
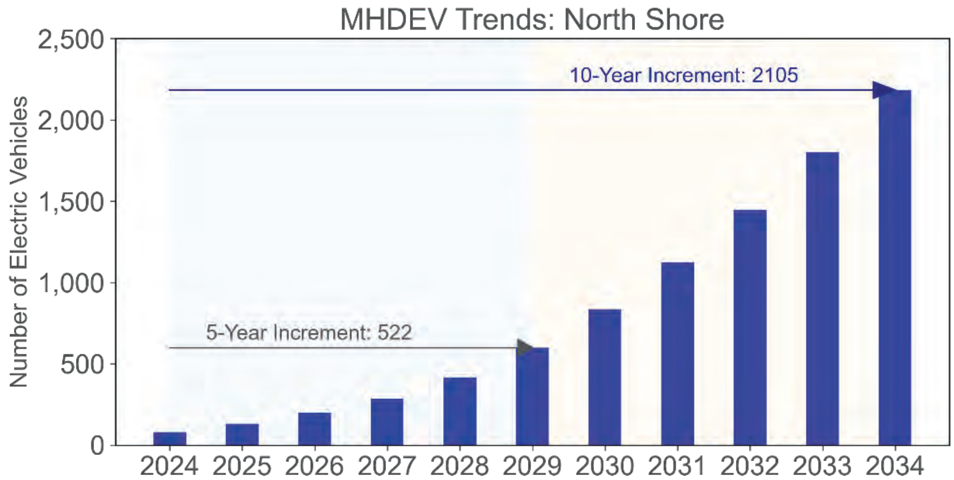


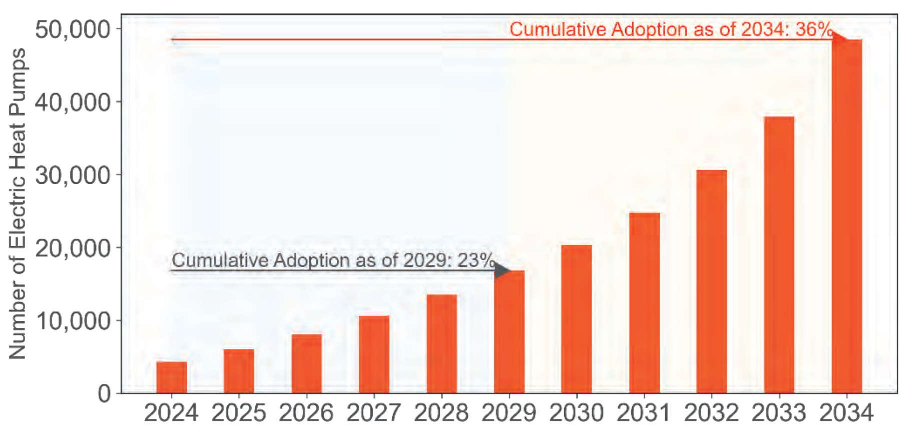
Exhibit 5.33: MHDEV Adoption Trend – North Shore Sub-Region



5.4.7 Heat Electrification

Among all six sub-regions, the North Shore has the second lowest EHP adoption trend forecast in the next decade owing to its low reliance on delivered fuel for heating. The total number of EHPs is set to rise to about 18,000 units by 2029 and exceed 50,000 by the end of 2034, resulting in about 36% overall penetration.

Exhibit 5.34: EHP Adoption Trend – North Shore Sub-Region



5.5 Southeast Sub-Region

5.5.1 Aggregate Demand – Summer and Winter

The Southeast sub-region is forecasted to have significant load growth due to an intermediate EV adoption trend.

Exhibit 5.35: Load Change from 2022-2029 – Southeast Sub-Region

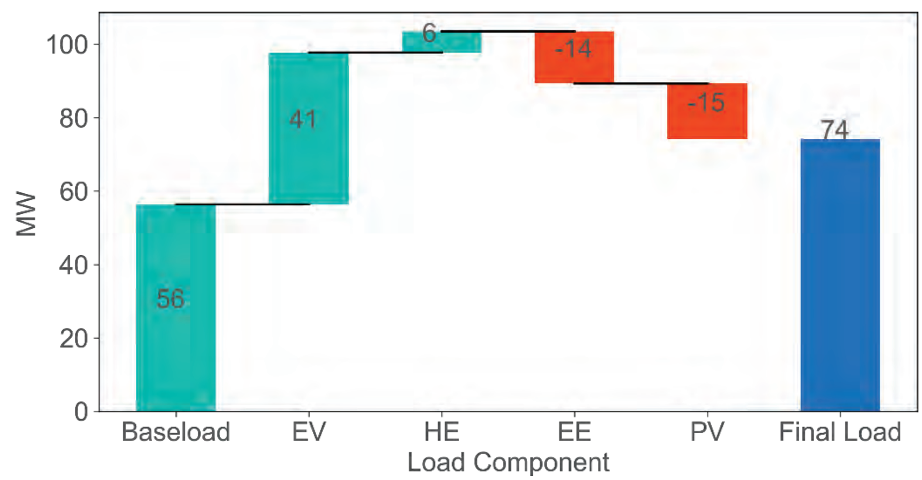
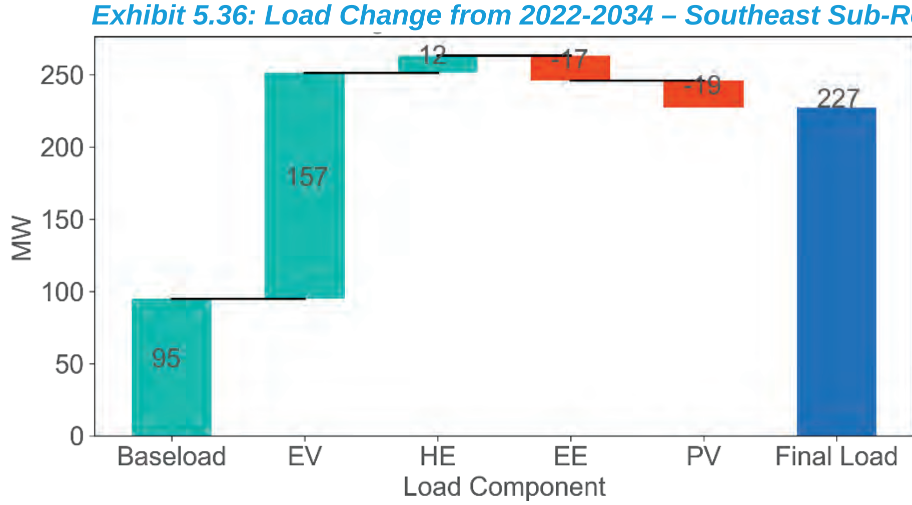


Exhibit 5.36: Load Change from 2022-2034 – Southeast Sub-Region



5.5.2 Weather Normalized Econometric Forecast

The Southeast sub-region falls primarily into the Southeastern Massachusetts (SEMA) load zone. The forecast for the SEMA load zone is discussed in the Appendix. Overall, the SEMA load zone forecast shows a CAGR of 1.3% by 2029 and 1.2% by 2034. The Southeast sub-region is expected to experience an average 0.8% annual growth both by 2029 and through 2034, which makes the region's baseload grow the slowest of all the sub-regions.

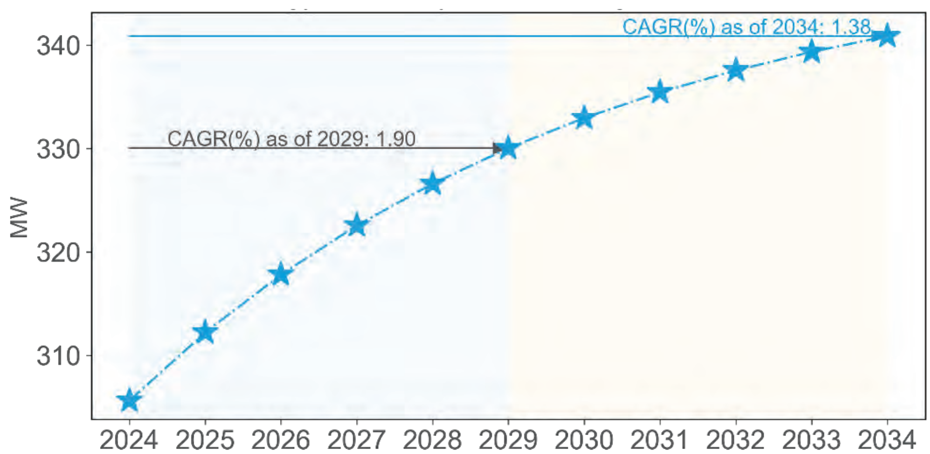
5.5.3 Large Load (Step/Spot Load)

Large load (step/spot load) impact is developed and handled in the system planning process. Please refer to Section 6 of this plan for further discussion.

5.5.4 Energy Efficiency

In addition to the SEMA load zone, the Southeast sub-region falls partially into the WCMA ISO load zone. Both exhibit substantial overall electricity demand. The EE saving projection is expected to grow steadily from current savings of approximately 300 MW and accumulate throughout the decade, with about 341 MW of peak demand savings by the end of 2034.

Exhibit 5.37: EE Peak Savings – Southeast Sub-Region



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

Strong PV growth is expected in the Southeast sub-region based on current projects in the queue as well as parcel analysis and the nature of the area being predominantly suburban. The Company forecasts that the cumulative non-rooftop solar nameplates will rise to approximately 420 MW by the end of 2029 with an additional 116 MW of projects realized by 2034. Rooftop solar PV also will experience steady growth, reaching 275 MW before the end of 2034. See Exhibits 5.38 and 5.39 for a graphical representation of rooftop solar and non-rooftop solar trends, respectively.

Exhibit 5.38: Rooftop Solar Adoption Trends – Southeast Sub-Region

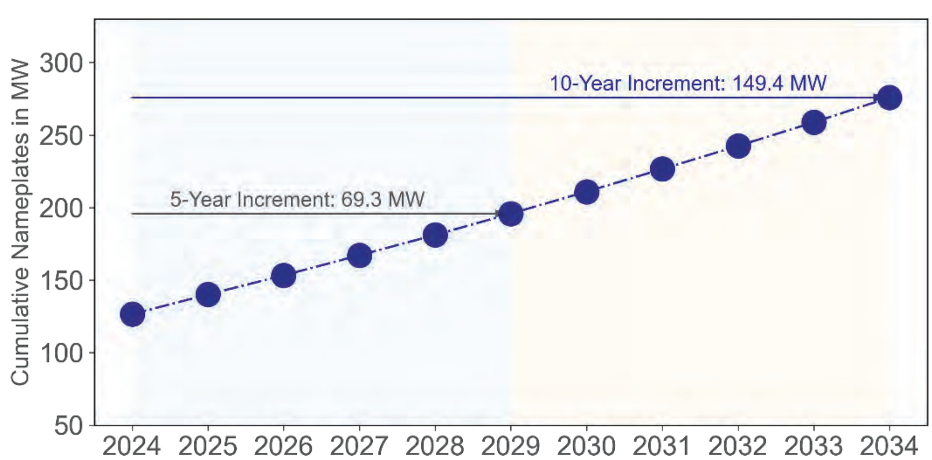
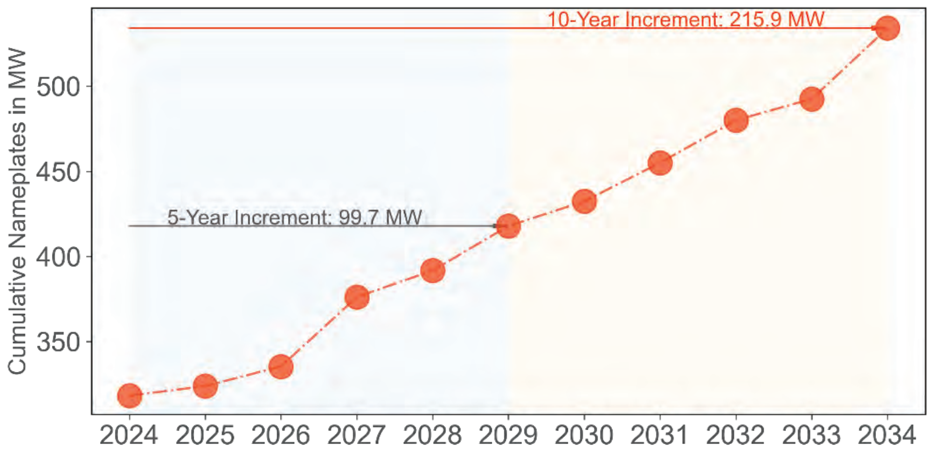


Exhibit 5.39: Non-Rooftop Solar Adoption Trends – Southeast Sub-Region



5.5.6 Electric Vehicles

The overall EV sales trend in the Southeast Sub-Region is projected to grow in alignment with the recent market outlook as well as the Commonwealth's targets. By the end of 2034, the Company's forecasts show that about 200,000 LDEVs and about 4200 MHDEVs will be in operation in the sub-region. See Exhibits 5.40 and 5.41 for a graphical representation of LDEV and MHDEV trends, respectively.

Exhibit 5.40: LDEV Adoption Trends – Southeast Sub-Region

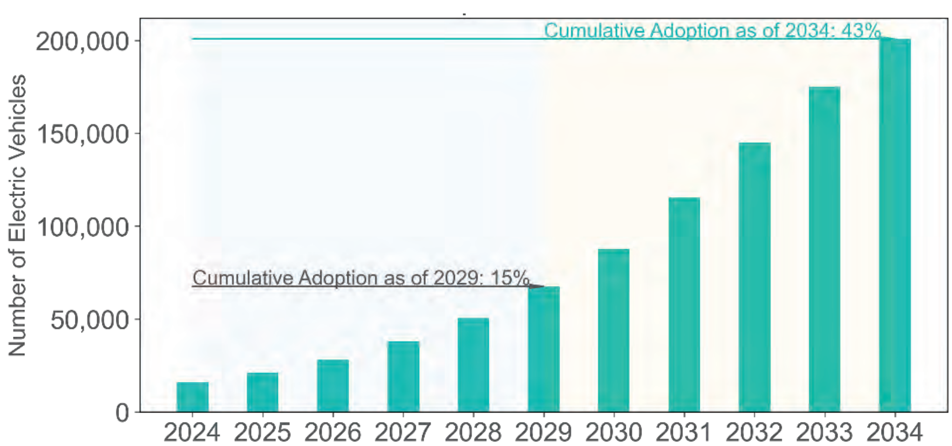
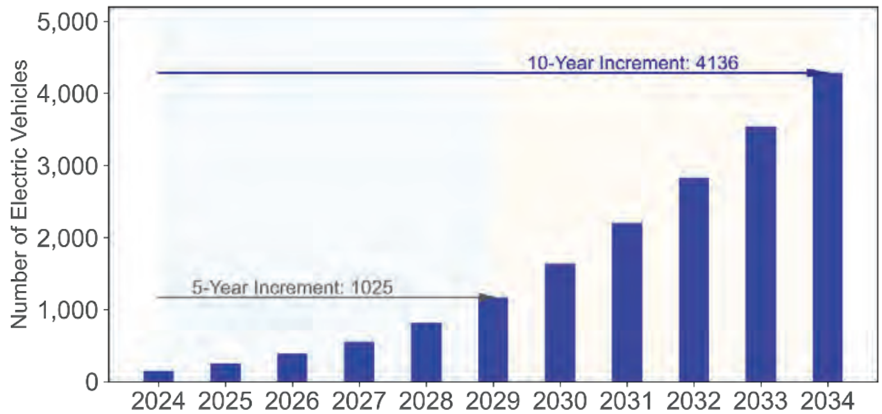


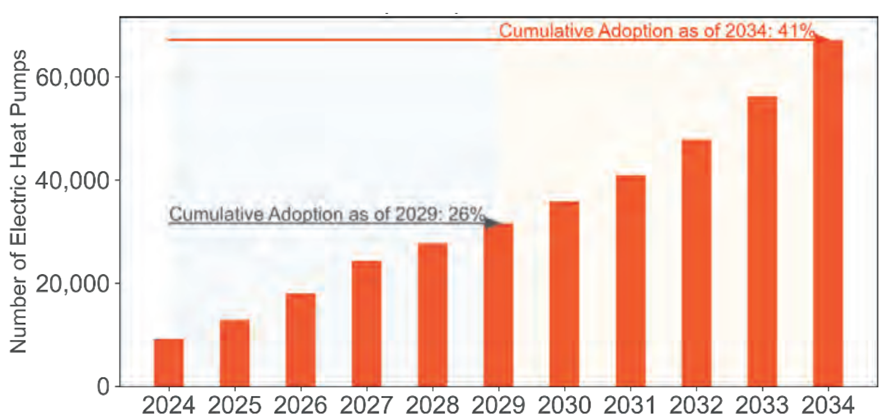
Exhibit 5.41: MHDEV Adoption Trends – Southeast Sub-Region



5.5.7 Heat Electrification

The Southeast sub-region currently has the most EHPs currently installed, and EHP growth is expected to continue in the sub-region through 2029, leading to an overall 26% heating electrification rate and 41% penetration before 2034. See Exhibit 5.42 below for a graphical representation of EHP trends.

Exhibit 5.42: EHP Adoption Trends – Southeast Sub-Region



5.6 South Shore Sub-Region

5.6.1 Aggregate demand – Summer and Winter

The South Shore sub-region's DER forecasts indicate relatively high growth in EV penetration, high EE savings, and moderate PV increases. The rapid EV growth will cause the region to switch from an afternoon to an evening peak hour sooner than other sub-regions. Exhibits 5.43 and 5.44 below show forecasted load change by 2029, and 2034, respectively.

Exhibit 5.43: Load Change from 2022-2029 – South Shore Sub-Region

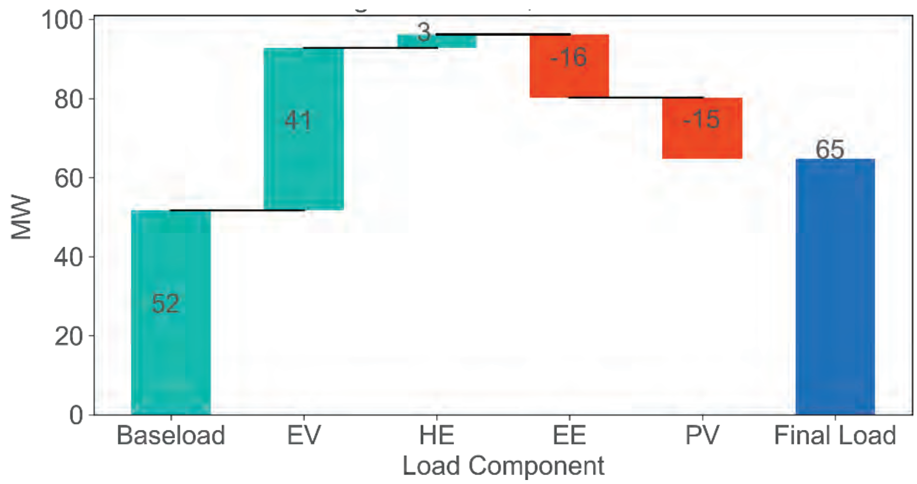
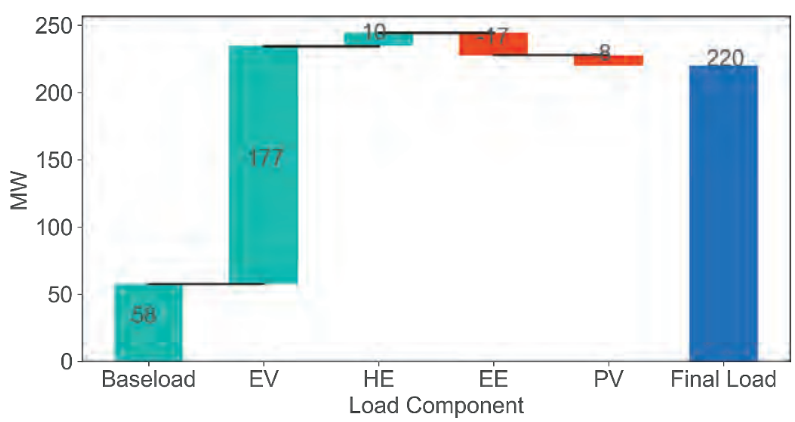


Exhibit 5.44: Load Change from 2022-2034 – South Shore Sub-Region



5.6.2 Weather Normalized Econometric Forecast

The South Shore sub-region is entirely within the SEMA load zone. The SEMA zonal forecast is discussed in the Appendix. Annual growth for the South Shore sub-region is expected to be moderate at 0.8% by both 2029 and 2034; the least significant growth pattern of all sub-regions.

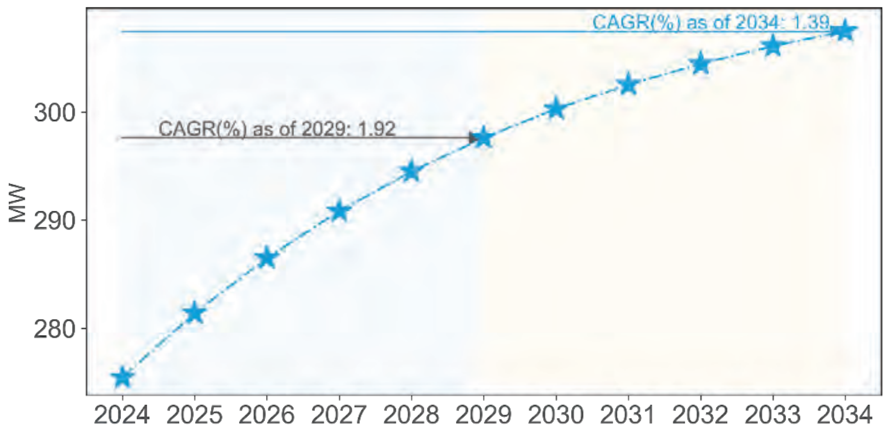
5.6.3 Large Load (Step/Spot Load)

Large load (step/spot load) impact is developed and handled in the system planning process. Please refer to Section 6 of this plan for further discussion.

5.6.4 Energy Efficiency

The South Shore sub-region's EE saving trend is largely associated with the SEMA zonal EE forecast. Due to the current substantial peak demand, peak savings are expected to increase to about 300 MW by the end of 2029 and 310 MW by 2034. Exhibit 5.45 below shows expected growth in EE savings for the sub-region.

Exhibit 5.45: EE Peak Savings – South Shore Sub-Region



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

Rooftop solar is anticipated to grow continuously through 2034 in the South Shore sub-region and approach cumulative installation of 300 MW. In terms of ground mounted PV, given that the region has fewer DG projects in the queue than other sub-regions and that it has less availability of cost-effective parcels compared to other sub-regions, only mild growth is expected, eventually reaching 180 MW around 2034. Exhibits 5.46 and 5.47 below show expectations for rooftop PV and other PV, respectively.

Exhibit 5.46: Rooftop Solar Adoption Trends – South Shore Sub-Region

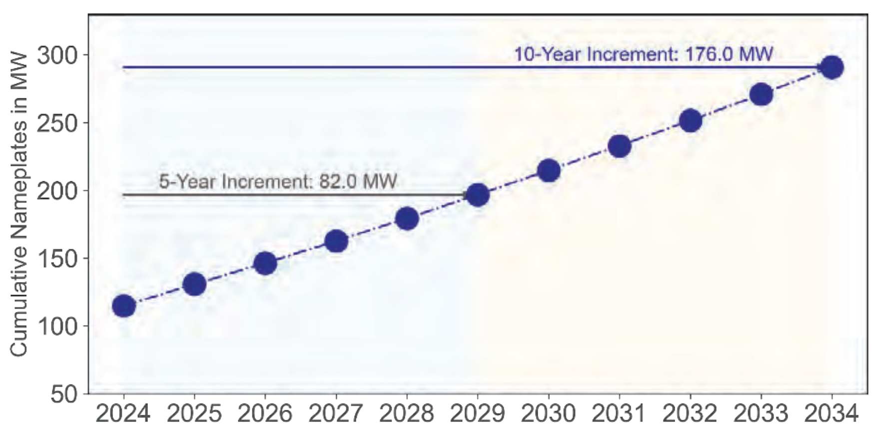
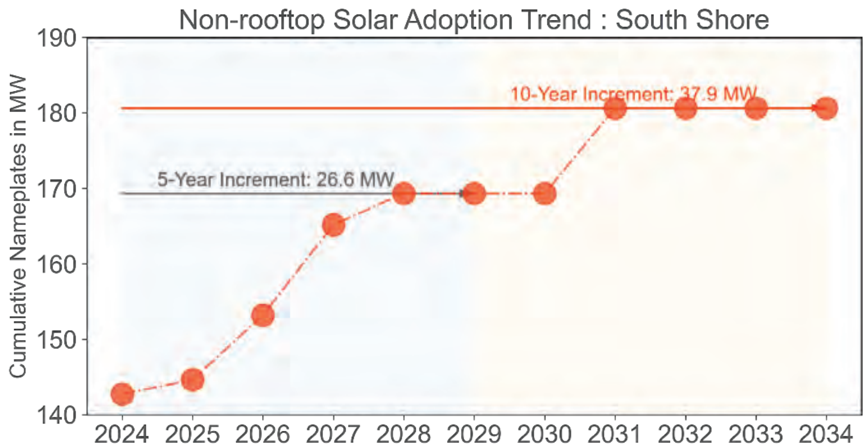


Exhibit 5.47: Non-Rooftop Solar Adoption Trends – South Shore Sub-Region



5.6.6 Electric vehicles

Significant EV growth is expected to take place in the South Shore sub-region owing to local socioeconomics and large commercial customer counts. The LDEV ownership percentage is forecasted to reach 50% (with about 240,000 vehicles) by the end of 2034 while, for MHDEV, the number of vehicles is expected to surpass 3,500 around the same time. Exhibits 5.48 and 5.49 below show expectations for LDEV and MHDEV trends, respectively.

Exhibit 5.48: LDEV Adoption Trends – South Shore Sub-Region

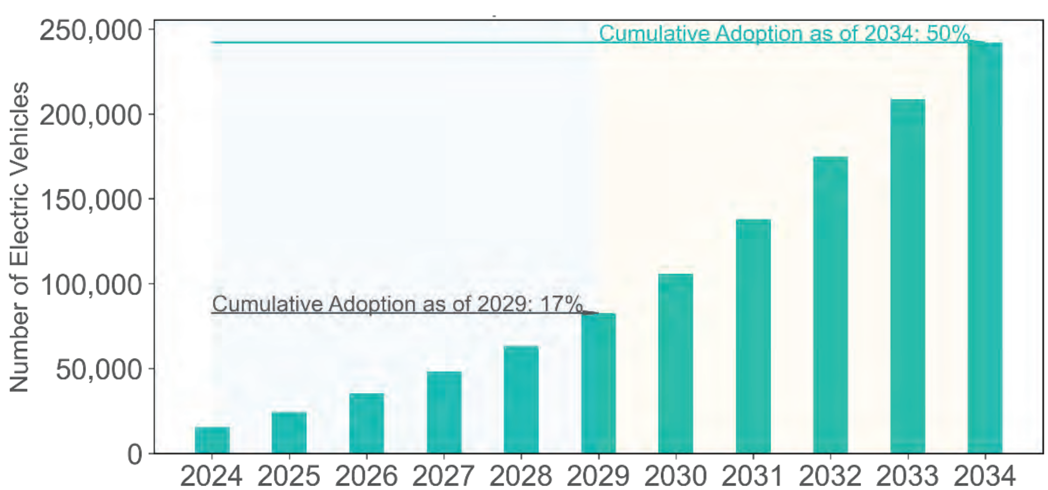
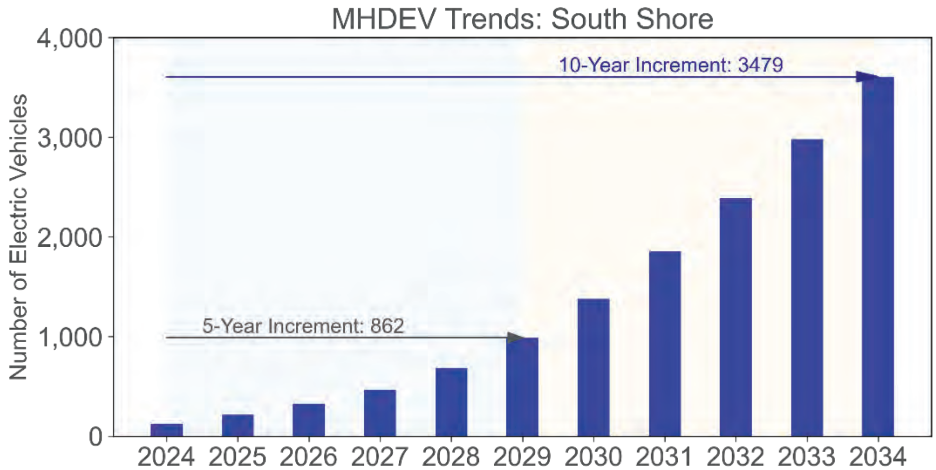


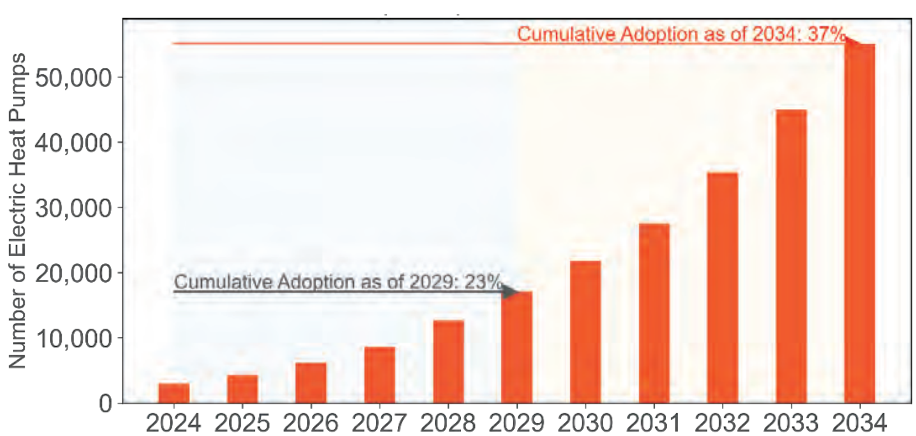
Exhibit 5.49: MHDEV Adoption Trends – South Shore Sub-Region



5.6.7 Heat Electrification

Moderate heating electrification is expected to take place in the South Shore sub-region between 2024 and 2034, with an overall 23% adoption by 2029, and 37% by the end of the 10-year horizon. Exhibit 5.50 below illustrates this trend.

Exhibit 5.50: EHP Adoption Trends, South Shore Sub-Region



5.7 Western sub-region

5.7.1 Aggregate Demand – Summer and Winter

The Western sub-region has the smallest electric load demand and is expected to have strong load growth with significant DER adoptions especially in PV and EV. Exhibits 5.51 and 5.52 below show expected load growth changes for the sub-region by 2029 and 2034, respectively.

Exhibit 5.51: Load Change from 2022-2029 – Western Sub-Region

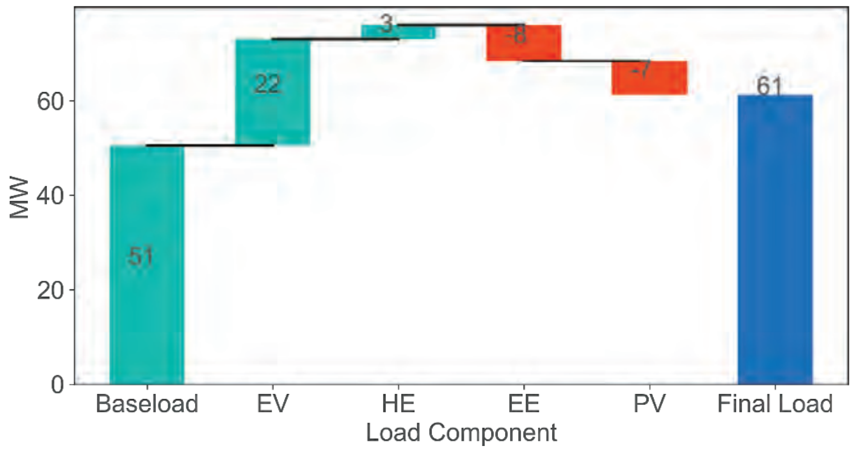
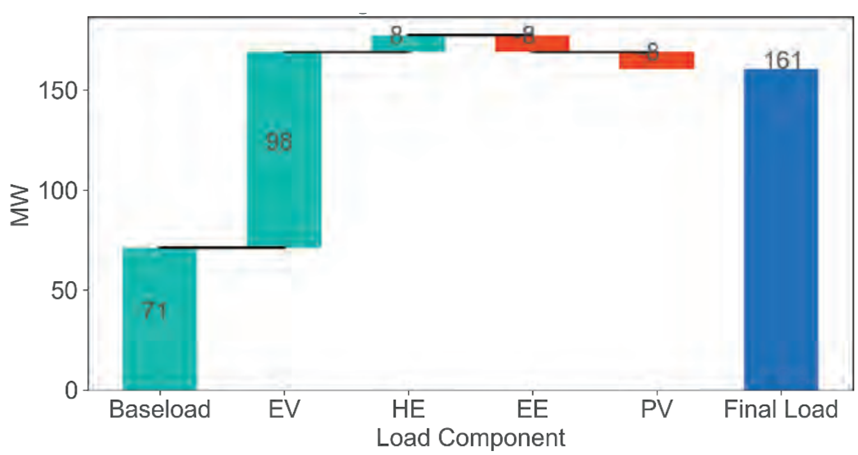


Exhibit 5.52: Load Change from 2022-2034 – Western Sub-Region



5.7.2 Weather Normalized Econometric Forecast

The Western sub-region falls entirely into the WCMA load zone. The forecast on WCMA is discussed in the Appendix. Overall, the WCMA load zone is expected to experience a CAGR of 1.2% by 2029 and 1.1% by 2034. The Western sub-region is expected to average 2.1% annual growth by 2029, and 1.8% through 2034. This is the highest econometric growth rate of all sub-regions.

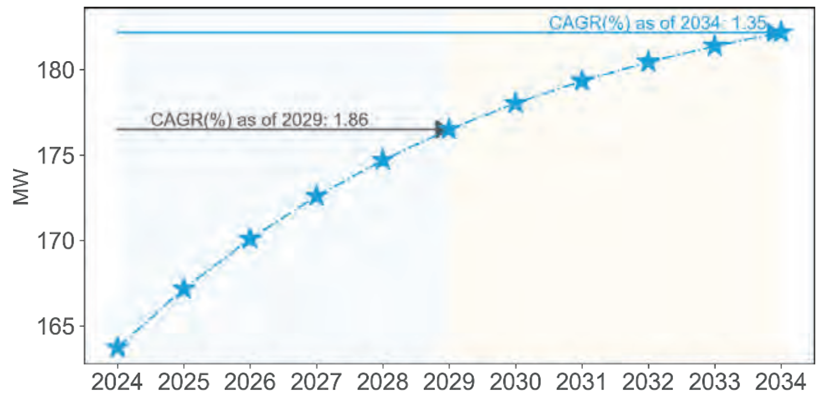
5.7.3 Large Load (Step/Spot Load)

Large load (step/spot load) impact is developed and handled in the system planning process. Please refer to Section 6 of this plan for further discussion.

5.7.4 Energy Efficiency

EE savings in the Western sub-region are moderate overall due to the sub-region's low energy consumption. The EE savings trend follows the same steady growth pattern as ISO-zone WCMA as a whole. The CAGR is 1.9% ending in 2029, and 1.4% for the Company's 10-year horizon ending in 2034, resulting in the sub-regional EE savings rising from 164 MW to about 182 MW. Exhibit 5.53 below illustrates the expected trend.

Exhibit 5.53: EE Peak Savings – Western Sub-Region



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

Due to the smaller number of customers in the Western sub-region, the Company forecasts a 5-year incremental growth in rooftop solar PV of 31.2 MW, and a 10-year incremental growth of 69 MW when compared to 2024. In terms of non-rooftop solar, the Western sub-region has sufficient cost-effective parcels, boosting projections of non-rooftop solar PV growth. Based on current project queue information, the sub-region is projected to have incremental growth of 126.8 MW in non-rooftop solar PV through 2029 and 385.8 MW by the end of 2034, leading to 800MW of solar projects in total when rooftop and non-rooftop PV are combined. Exhibits 5.54 and 5.55 below illustrate trends for rooftop solar PV and non-rooftop PV, respectively.

Exhibit 5.54: Rooftop Solar Adoption Trends – Western Sub-Region

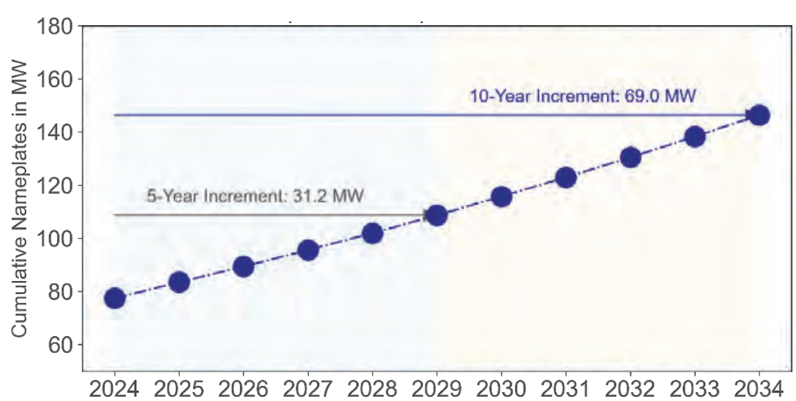
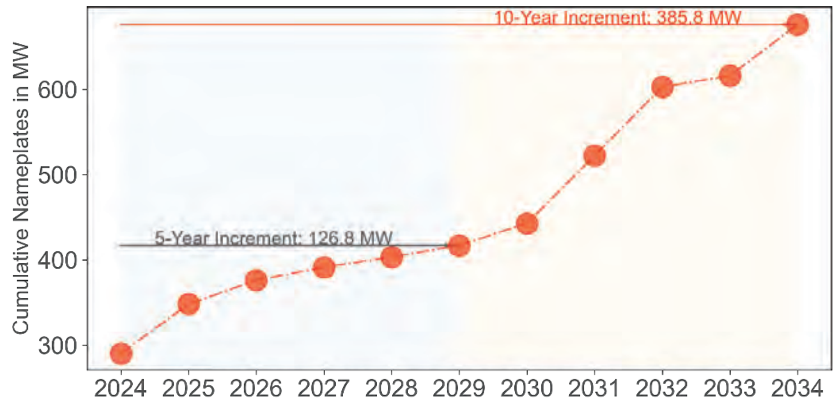


Exhibit 5.55: Non-Rooftop Solar Adoption Trends – Western Sub-Region



5.7.6 Electric Vehicles

As one of the least populous regions within the Company's service territory, the Western sub-region is projected to witness the adoption of approximately 30,000 additional LDEVs between 2024 and 2029, resulting in an estimated 14% market share for LDEVs by the end of 2029. Continuing this upward trajectory with greater growth trends, LDEVs in the Western sub-region are forecasted to account for about 50% of all light duty vehicles in operation by the end of the 10-year forecast horizon. The MHDEV trend exhibits a similar pattern with about 2,300 MHDEVs by the conclusion of 2034. Exhibits 5.56 and 5.57 below illustrate these trends for LDEVs and MHDEVs, respectively.

Exhibit 5.56: LDEV Adoption Trends, Western Sub-Region

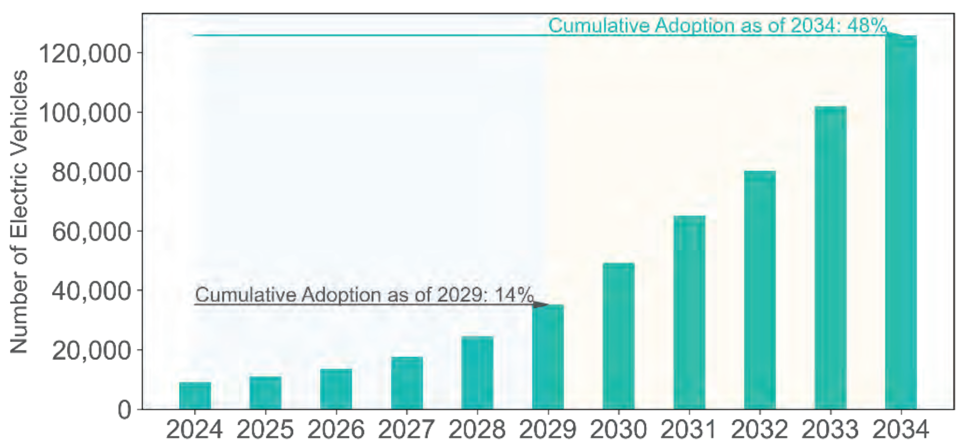
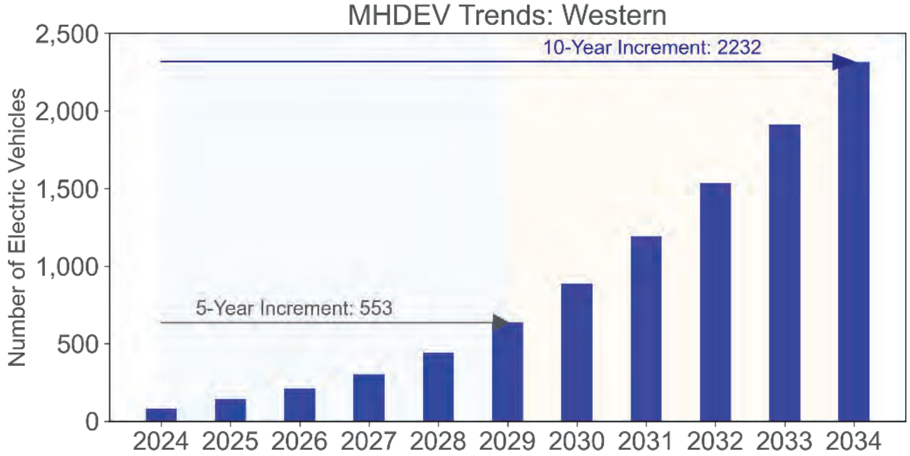


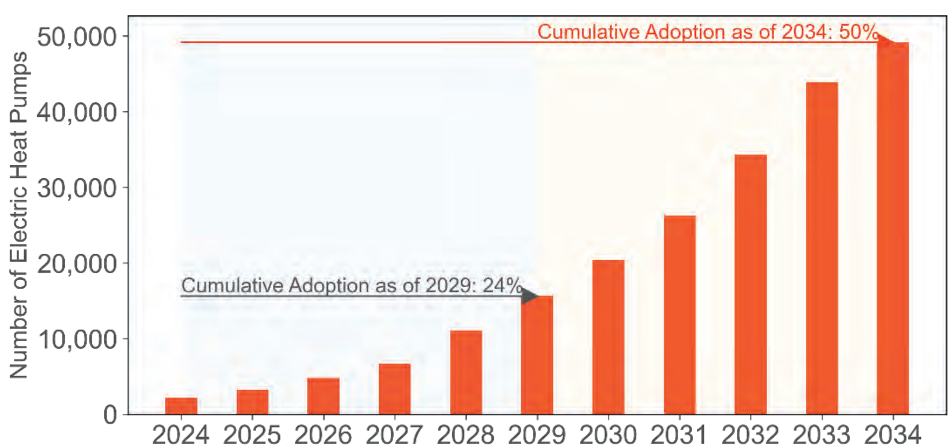
Exhibit 5.57: MHDEV Adoption Trends, Western Sub-Region



5.7.7 Heat Electrification

Because a significant share of households in the Western sub-region use delivered fuel for heating, the Western sub-region is expected to witness rapid growth of EHP adoption in the next decade. The overall adoption rate of EHPs for residents within this sub-region is forecasted to reach 24% by the end of 2029, and 50% for 2034.

Exhibit 5.58: EHP Adoption Trends – Western Sub-Region



Section 6

5- and 10-Year Planning Solutions: Building for the Future

This section describes the new investments and programs that the Company proposes to implement over the next five and ten years and how they will create value for customers and accelerate delivery of the Commonwealth's Net Zero commitments.

Key Take-Aways

- Over the period from 2025-2034 considerable growth in customer load on the Company's network is expected due to electrification of transportation and heating, adoption of DERs like solar and ESS, and reliability expectations from customers depending more centrally on the Company's electric network for their transportation and heating needs.
- The current network is not big enough to meet this growth. It takes multiple years to develop, design, and deliver investments, and so proactive investments in a stronger network must be made now to keep up with the load growth.
- Not only will the electric network need to be stronger, it will also need to be smarter as the Company manages a more complex and dynamic network. The Company will build on the progress of Grid Modernization investments to develop a complementary set of advanced technological capabilities required to manage a more dynamic, reliable, and DER-heavy network that supports new customer offerings.
- The Company will leverage its new technology capabilities and customer offerings to accelerate the adoption of clean energy technologies by delivering NWAs that will both offset the need for investment and support the continued connection of customers' EVs and EHPs at pace as the Company continues to build out the network
- While implementing those network infrastructure projects, new programs and scaled existing programs will be deployed to empower the Company's customers to participate in the clean energy transition, both by helping them install and adopt clean energy technologies like EVs, EHPs, and EE, and by creating opportunities for them to take more ownership of their bill via new rate structures and programs that value customer flexible demand.
- To deliver at the pace required the Company will need to work differently, and it will also need regulatory, policy and permitting changes to enable the quicker delivery of these critical investments.

6.0 5- and 10-Year Planning Solutions: Building for The Future

The purpose of this section is to discuss the 5- and 10-year investments and programs that the Company plans to deploy to meet customers' evolving needs and to stay on track with delivery of the Commonwealth's 2050 Net Zero goals. The Company includes in this chapter physical network infrastructure investments, customer-facing programs, and technology platforms and initiatives. This section:

- Provides a comprehensive outlook (and summary) of investments and programs that are already in-flight and/or approved via prior regulatory proceedings.
- Outlines more detailed proposed investments and programs that the Company introduces for the first time or intends to scale as part of this Future Grid Plan.

While talked about separately in this Future Grid Plan, these investments and programs all come together to deliver the network of the future with capabilities from each investment building on the others to create a smarter, stronger, cleaner grid for all Company customers.

Exhibit 6.1: Summary of Proposed Investments and Programs

Load growth is accelerating from customer adoption of beneficial electrification technologies. As described in Section 5, increased load driven primarily by adoption of electric transportation and heating is expected to increase the peak load across the network by 7% in 2029 and 21% by 2034 relative to 2022 levels, with some variability by location. At the same time, Company customers are increasingly turning to DERs and their expectations around reliability are increasing. These trends are welcome and necessary to achieve the Commonwealth's GHG reduction goals, but also necessitate increased infrastructure investments. The Company's nation-leading investments in EE and solar programs have historically helped avoid the need for substantial infrastructure investments. These programs will continue to be important to manage increasing load growth but the Company anticipates moving from a world in which they are largely sufficient to manage increased load, to a reality in which demand growth is so great that they function to give the Company time to match infrastructure construction with the increased load. In addition, the future foreseen involves a more complex network where the Company is increasingly managing DERs, and new grid automation and controls. If managed appropriately, this complexity will allow the Company to slow infrastructure investment to some extent, but to take full advantage of these flexible grid resources the Company will need to increase investment in technology and data management platforms.

As described within this section, in several instances the expected load growth could result in overloads of existing equipment, which would severely threaten the safe and reliable operation of the network, if not matched with appropriate increases in infrastructure. Below are the details of several proposed investments across the Company's network to proactively address these expected overloads by delivering sufficient network capacity when the Commonwealth needs it to support customers' adoption of electric transportation and heating. Critically, network investments need to be proactive instead of reactive. In the Company's Future Grid Plan, the Company is recommending significant investment so that systems can keep pace with customer adoption of HPs, EVs, and other forms of transportation electrification. The increased capacity on the system will be "multi-value" meaning that it will create additional headroom for both new load from electric heating and transportation, as well as for new DER interconnections. This is critical because beneficial electrification only occurs when clean electricity can connect to the grid. Similar to Section 4, the analysis and results for the infrastructure investments is presented by sub-region.

The clean energy transition will not happen without the active engagement of the Company's customers. The customer-facing programs described below in this section are intended to make it easier for customers to participate in the clean energy transition, including initiatives that will help reduce the costs and complexity for customers to adopt and install EH, EVs, EE, ES, and solar. The customer-facing initiatives also include ways for customers to take greater ownership of their bills through enhanced insights into how they use energy, new rate options, and expanded opportunities to earn value as "prosumers" via grid service programs, which will become increasingly critical components to the Company's successful delivery of a clean energy network as NWAs.

Technology investments are the critical enabler that will allow the value of the customer and network investments to be maximized as a more complex network is developed. To highlight a few key areas of technology investment discussed below, the Company, as part of this Future Grid Plan is further scaling its recently approved Grid Modernization investments to deliver more benefits for Company customers, as well as investing in new critical technology capabilities, particularly related to management of DERs and activating customer flexibility to help reduce the pace and scale of required network buildout and to achieve more dynamic network operations. Additionally, the Company is building enabling capabilities related to data capture and management, security, and new digital tools, including those to accelerate the pace and delivery of network infrastructure projects.

6.1 Summary of Existing Investment Areas and Implementation Plans (Existing Asset Management and Core Investments, Including Rate Case, Grid Modernization, Approved CIP Programs, Decarbonization, Heating, Electric Vehicle and Energy Efficiency Programs)

This section summarizes existing investment areas, programs, and initiatives that have been approved in prior filings. The table below includes descriptions of some of the key investments and where applicable includes links to the relevant dockets and filings.[1]

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[1]Note, the company has previously provided the GMAC with a summary of relevant dockets: https://www.mass.gov/doc/gmac-mtng-4-preread-esmp-relevant-proceedings-and-working-groups-version-2/download

Exhibit 6.2: Summary of Approved Investments and Programs

<table>
<tr><th>Investment Area</th><th>Summary of Approved Investment / Program</th></tr>
<tr><td>Core Investments</td><td>The Company’s core capital investment activities (i.e., “base spending”) cover a range of project categories required to maintain safety and reliability of the network under relatively status quo conditions. The Company’s core capital investment are described more completely in Section 7.1, though in brief include:
Asset Condition, including substation replacements and retirements, implementation of the Inspection and Maintenance program and the proactive replacement of direct-buried underground cables.
System Capacity and Performance, including large substation expansions necessary to increase area capacity and the transformer replacement program.
Damage/Equipment Failure and Customer/Public Requirements, which are investment requirements that the Company has an obligation to fulfill, but which are not under the Company’s control.
Climate Resilience, which include incremental capital investments in hardening distribution system infrastructure to address impacts of climate change as identified by recent climate impact analysis.
Non-Infrastructure, which represents capital investment that does not fit into one of the foregoing categories, but which is necessary to run the electric system.</td></tr>
<tr><td>Grid Modernization Plan (GMP)</td><td>The collective technology investments and demonstrations outlined below will significantly modernize the Company’s network management and communications capabilities, ability to operationalize data to transform how the network is operated, as well as security.

The Company received approval on its second GMP (for the years 2022-2025) via two separate Orders in October and November 2022. The Orders authorize investments in the following:
ADMS: enabling real-time management and control of the Company's electric distribution network.
Feeder monitors: enabling real-time visibility into the Company's electric distribution network.
Advanced Distribution Automation / Fault Location Isolation Service Restoration (FLISR): system that identifies and automatically resolves problems on the distribution system improving system reliability, reducing customer outage time and increasing customer satisfaction.
Conservation Voltage Reduction (CVR) and Volt/Volt-Amps Reactive Optimization (VVO): system that optimizes distribution system voltage, resulting in reduced energy demand and lower costs to customers.
Communications: Secure and reliable communications networks to meet customer and Company needs.
Information technology, data management and integration, and security: improving the technology foundation to deliver, “any data, any service, any time” via data management and analytics, integration services, and cyber security investments.</td></tr>
</table>

	• **DERMS**: used to plan, track, manage and operate DERs. The system includes features such as short-term forecasting, grid edge control, DER dispatch, and market platform. • **ARI demonstration projects** to field test DERMs capabilities to deliver a new flexible interconnection option to accelerate DG interconnections. • **Local export power control demonstration projects** to reduce interconnection cost and time for customers adding load and generation on the system at the same time. The solution locally manages the customer assets so it has defined net impact on the system.
Advanced Metering Infrastructure (AMI)	The Company received approval on its AMI plan in 2022. The order authorizes the Company to replace its existing AMR meters and supporting systems with AMI The AMI plan includes the widescale deployment of smart meters across the network and accompanying back-office technology that will transform the ways in which Company customers can access their energy usage data and manage their energy consumption, as well as improve the ways in which the network is operated and planned. The deployment of AMI will be implemented on a rolling basis and is expected to be fully complete by the end of 2027
Energy Efficiency (EE)	The Company's most recent three-year EE plan (2022-2024) authorizes the Company to administer various EE, DR, and EHP incentives programs as part of Mass Save, investing $1.28B for electric EE and $0.67B for gas EE. These programs provide bill savings benefits for participating customers and broader social benefits (such as those from peak shaving) that benefit the Company's overall customer base. • EE – the Company administers a comprehensive set of nation-leading incentive programs designed to help customers across all segments identify energy inefficiencies in their homes and businesses and address those inefficiencies by leveraging rebates to install new measures to reduce their energy consumption. • DR – program that incentivizes commercial, industrial, and residential customers to curtail and/or shift their energy when the electricity demand is forecasted to be at its peak. The Company administers several DR programs via ConnectedSolutions focused on reducing load across the network when the collective network is at peak. The programs include thermostats, ES, EVs, and large curtailable loads at C&I facilities. • EHP Incentives – program that offers rebates based on equipment capacity to residential and commercial customers who install EHPs, to supplement or replace a pre-existing oil, propane, natural gas, or electric resistance heating systems.
Electric Vehicles (EVs)	The Company's EV Phase III Program approved in Dec 2022 and covering Jan 2023 through Dec 2026 s a comprehensive set of offerings designed to support the growth of EVs in the Commonwealth of Massachusetts, including: • Residential: incentives to provide at-home electrical upgrades, charger installations, and off -peak charging (includes individual residential customers and multi-unit dwellings). • Public and Workplace: make-ready, charger, and networking incentives to enable widespread access to charging across communities.

	• Fleet: make-ready and charger incentives to assist with electrifying fleet vehicles, including light -, medium and heavy-duty, as well as fleet advisory services • Demand Charge Alternative Program (2023-2032): a program helping to reduce the operating costs of fast chargers and accelerate deployment. Provides a tiered load factor-based demand charge discount to separately metered EV charging customers.
Pending Capital Investment Plans (CIPs)	The Company has proposed a set of capital investments required to interconnect solar PV and ES projects in specific areas with a cost allocation methodology that reflects the multi-value nature of projects. The Future Grid Plan network infrastructure analysis and resulting proposed investments assumes that the Company's pending CIP proposals are approved. The specific CIP proceedings that are underway have been identified for each sub-region in Section 4.

Customer Programs to address EJCs:

The Company recognizes that populations in EJCs may face barriers to participation in programs that help manage bills or provide opportunities for customer participation in the clean energy transition. The Company's existing 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, such as engagement through the EE Equity Working Group to set specific goals for equity and service to EJ populations. For EE programs and for EVs, more enhanced EJC incentives are offered for residential customers and more direct support of fleet electrification is a priority to reduce local air pollution.

Exhibit 6.3: Summary of EJC Incentives/Offerings

Program	EJC Incentive / Offering
EVs – Public Fleet Infrastructure rebates for EJCs	• Up to 100% utility-side infrastructure incentives • Up to 100% customer-side infrastructure incentives • Up to 100% charger rebates for income-eligible EJCs; Up to 75% charger rebates for other EJCs; • Up to 50% charger rebates for non-EJCs
EVs – Residential EV Charging incentives for EJCs	• Up to $1000 rebate for in-home EV charging infrastructure upgrade when enrolling in managed charging program for single family in an EJC • (Up to $2000 rebate for 2-4 family)
EE upgrades for low-income customers and multi-family residents	• All eligible energy efficiency upgrades to low-income customers, and multifamily buildings with 50% or more low-income tenants, at no cost.
Weatherization for all rental units	• 100% no cost home weatherization for all rental units.

6.2 Design Criteria Changes (If Applicable)

Common with all EDCs, the Company has Engineering Planning Criteria which set out when and how the network should be planned and built to meet its requirements. The Company utilizes Distribution Engineering Planning Criteria, which establish the standards by which planners evaluate issues such as thermal loading, voltage limits, protection analysis, and reliability, and set thresholds the planning engineers use to determine when a project is needed and how to appropriately size the solution to that need.

With increased electrification there will be growth in electric demand and a need for greater reliance on the system. Thus, the Company must design and operate a system that keeps pace with future changing needs. Today there are many capacity constraints on the system and keeping pace means the Company will need to build the system in an anticipatory manner by adding capacity so it is in place when and where customers need it. This will enable faster customer connections. Customers also will expect a system that is reliable such that they have power during adverse system condition events; examples include things such as a failure of a substation supply transformer or a storm event. This also requires building the system to more stringent Engineering Planning Criteria. As a result, the Company's Engineering Planning Criteria will continue to evolve.

6.3 Technology Platforms That Are Being Implemented (Including AMI With Data Access, VVO, FLISR, ADMS, DERMs (To Optimize 20-Year Solution Set), Automated Interconnection Tools, Etc.

The Company proposes to build on its currently in place and in-progress technology platforms, including those approved via the Grid Modernization Plans and described in the chart in Section 6.1, with new investments to support delivery of the Future Grid objectives. See Section 4.9 for a discussion of the technology platforms the Company has in place today. This Section 6.3 provides an overview of technology platforms necessary in the next 10 years, which includes already approved and in-flight platforms (as well as expansions or enhancements to them in this ESMP) and new technology platforms introduced in this Future Grid Plan.

Consistent with the framework introduced in Section 4.9, technology investments are described in the following categories:

1. **Network management and communications** includes the technologies used to communicate with, monitor and control assets on the network, including company-owned assets and customer DERs, and technologies needed to manage and respond to grid outages and abnormal system conditions.
2. **Metering and billing systems** include the technologies used to measure customer energy usage on the network and issue accurate bills based on those meter reads.
3. **Customer portals** include the customer-facing as well as internal systems used to support customer clean energy programs such as those related to EE, EV, and new customer interconnections. This bucket of technology investments help to accelerate customer adoption of clean energy technologies and improve the customer experience.
4. **Data** includes the type of data that the network, planning and operations, and customers have access to, as well as the Company's ability to manage, integrate, and operationalize that data to transform how the grid is operated and planned.
5. **Asset planning, management, and work execution** includes the systems used to support grid planning and design, construction and capital deployment, and system maintenance and field operations.
6. **Security** includes measures in place to ensure the security of the technology systems from potential cyber threats and attacks.

Exhibit 6.4 below categorizes the needed technology investments that are in flight and already approved via a recent filing, as well as incremental investments proposed in the Future Grid Plan.

Exhibit 6.4: Summary of Needed Technology Investments

#	Category	In-flight/Already Approved	Proposed (to be funded via Future Grid Plan)
1	*Network Management and Communications*	• ADMS • DERMs Phase I • FLISR • VVO / CVR • Grid modernization communications	• Active power restoration services (ADMS extension) • DERMs Phase II • Expanded FLISR • Expanded VVO/CVR • Expanded grid modernization communications • Enterprise network communications • Future of network management demonstration projects
2	*Metering and billing systems*	• AMI	• TVR billing system engine
3	*Customer portals*		• Clean Energy Platform 2.0 • DER customer experience enhancements
4	*Data*	• Data management platform • AMI	• Intelligent data capture • Grid asset data enhancements
5	*Asset planning, management, and work execution*		• New digital products to support ESMP objectives
6	*Security*	• Foundational security investments	• Enhanced security investments

6.3.1 Delivering Technology in a Rapidly Evolving Industry

As the distribution network continues to evolve with the proliferation of DERs, EVs, and EHPs, so will the operational challenges and opportunities that face the network. Therefore, the Company is continually seeking innovative ways to deliver new products and services efficiently. As an EDC, the Company's challenge lies in adapting to the changing needs of Company customers while continuing to ensure a secure, affordable, and safe electric service. To address this challenge, the Company has and continues to lead the energy transformation through the delivery of industry leading digital products leveraging the Scaled Agile Framework (SAFe) shown in Exhibit 6.5 as a comprehensive approach to product delivery. SAFe is a widely used industry best practice, which has been successfully adopted across many industries including infrastructure, government, IT, and consumer goods.

The Company operates in an industry driven by regulations, complex infrastructure, and long-standing processes. However, the advent of renewable energy, grid modernization, and the increasing need for customer-centric solutions demands a new agility in the Company's operations.

By adopting SAFe the Company is:

- **Enhancing speed-to-market:** facilitating faster delivery of new products by streamlining processes, eliminating bottlenecks, and enabling cross-functional collaboration. This enables a swift response to market, customer, and business demands and changing customer needs.
- **Improving customer satisfaction:** emphasising customer-centricity and ensuring that new products are aligned with customer expectations. By involving customers early in the development cycle and leveraging feedback loops, solutions can be delivered that better meet customer needs, ultimately enhancing customer satisfaction.
- **Increasing operational efficiency:** promoting Lean-Agile principles and practices, encouraging continuous improvement, waste reduction, and optimized resource utilization. This approach helps to streamline the Company's operations, reduce costs, and improve overall efficiency.

Exhibit 6.5: SAFe Framework

Utilizing a framework that helps align product development efforts with the Company's business goals is hugely significant. It brings together Lean, Agile, and Systems Thinking principles into a comprehensive methodology, which helps to achieve enterprise-wide agility. The key elements of SAFe include:

- **Scalability:** designed to handle large-scale product development efforts, making it an ideal fit for the Company; an organization continuing to mature its product delivery approach. It allows for the coordination and synchronization of multiple teams working on complex projects, ensuring efficient collaboration, and minimizing interdependencies.
- **Cross-functional collaboration:** emphasizes the need for cross-functional teams to work together, breaking down silos and fostering effective communication. As a large multi-

national organization, this collaboration spans different departments, such as engineering, operations, customer service, and regulatory affairs, facilitating a holistic approach to product delivery.

- **Portfolio management:** ensures a structured approach to managing the portfolio of products and initiatives. It supports the prioritization of projects, allocation of resources, and ensures alignment with strategic objectives. This enables better decision-making and improved resource allocation to maximize business value.

In implementing SAFe, there area wide range of realized benefits, such as responding quickly to market and customer dynamics, and changing regulatory requirements. It has allowed the fostering of an environment where innovation thrives, enabling the introduction of new technologies and solutions that address evolving customer needs. The Company has internalized the value of taking an iterative and incremental approach, which promotes faster delivery and greater impact of products. By breaking down work into smaller, manageable increments and leveraging frequent feedback loops with key business and customer stakeholders, the Company has reduced the time it takes to bring new products to market and deliver value to its customers. Importantly adopting SAFe has ensured quality be accentuated at every stage of the product development lifecycle.

6.3.2 Description of Implementation Justification and Expected Benefits

1. **Network management and communications**

a. **ADMS**

Foundational investment:

As part of the GMP, the Company has made significant progress on its implementation of ADMS and has authorization to complete its deployment of the foundational ADMS program in 2025. The Company is thus not seeking additional funding to support its foundational deployment of ADMS as part of this Future Grid Plan. However, the Company includes below a brief description of how it envisions leveraging ADMS as an underlying foundational technology for future network management investments. As discussed below, new incremental features in ADMS will be deployed over time as needed to support future network management investments and use cases.

ADMS is a software platform that enables real-time visibility and control of the physical infrastructure making up the distribution system. The platform works to integrate SCADA, OMS, and DMS functionality into a common database and user interface. As the backbone of the of a modern distribution network management system, ADMS uses advanced algorithms, data analysis and modeling features to optimize the configuration and operation of the electric distribution network and provide a level of real-time visibility that the distribution control center has never had before. In particular, ADMS includes the ability to produce real-time load flow, which will be critical for the Company’s distribution control centers to monitor and control a network rich with DERs and ensure a more reliable and stable power supply for customers.

Managing voltage, frequency, and power flows, ADMS is the network management platform that not only operates the grid, but also opens up the opportunity for benefits from advanced capabilities that lower the cost of energy through VVO and CVR, improves reliability through Fault Location Isolation and Restoration (FLISR) and integrates more renewable energy and DERs through coordination with solutions like DERMS.

Incremental ADMS features to support DER integration into Outage Management Capabilities (Active Power Restoration Services):

As part of this ESMP, the Company requests additional funding to support the deployment of new features in ADMS to better integrate DERs on the network as part of the Company's outage restoration strategy.

Item "c" below describes how the Company is implementing FLISR across its network, a self-healing scheme involving the automatic opening and closing of switching devices on the distribution network to reroute power in the event of an outage on the network. As part of the GMP, the Company has approval to integrate its FLISR scheme into ADMS, which will provide advanced control of the switching devices, determine how much load can be safely rerouted and transferred from one part of the network to another, and lay the groundwork for future opportunities to improve the intelligence, speed, and coverage of the Company's outage restoration efforts.

Leveraging ADMS to support FLISR from a foundational perspective will be enormously helpful, but there is opportunity to improve the FLISR scheme beyond the currently scoped use cases by integrating customer-owned DERs into the Company's outage restoration strategy as part of an initiative called Active Power Restoration Services (APRS). As the Company continues to accelerate deployment of DERs on the network, the high penetration of DERs on the distribution grid will present challenges as well as opportunities for the existing FLISR scheme that APRS would address. In particular, as the Company scales and evolves centralized ADMS-based FLISR there is opportunity to, in partnership with DERMs, dispatch DERs as part of outage restoration along with switching devices, which would increase the load transfer capacity of the FLISR scheme and restore power to a larger number of customers.

b. DERMs

Following approval of the GMP, the Company has started to implement its DER Management Systems (DERMs) investments. The Company proposes in this Future Grid Plan to expand the functionality of and scale the Company's DERMs capabilities to deliver more benefits to customers and accelerate deeper integration of DERs into the network.

The Company's DERMs Platform refers to a group of individual software products managed by the Company that operate together in a cohesive fashion to actively track, plan, manage, and operate DERs interconnected to the distribution network through monitoring and control either directly or via an aggregator. DERMs works closely in conjunction with ADMS, which enables much of the underlying intelligence that the DERMs uses, to facilitate operational DER management. The DERMs functionality for which the Company has received authorized cost recovery to implement as part of the 2022-2025 Grid Modernization plan, includes the Company's first wave of DERMs capabilities and modules focused on short-term local forecasting, grid edge control, economic dispatch engine, and delivering a market platform.

Collectively, these approved investments are primarily intended to reduce the cost and timeline to interconnect to the network by delivering the capabilities required to support a flexible interconnection (i.e., the Company will implement active management of DER curtailment so that DER can connect in a constrained location without posing risks to the network). By reducing the cost and time for new DERs to interconnect to the system, these investments will help support the Commonwealth's DER adoption goals and will enhance customer experience by enabling a faster and lower-cost network access options for customers.

As part of the Company's Future Grid Plan, funding is being sought to progress an expanded set of DERMs features and modules that will be used primarily to:

- Continue to scale and expand capabilities for flexible connections beyond its initial ARI pilot to enable accelerated network access options to reduce interconnection cost and time for solar, ES, and EVs.

- Accelerate pathways to procure and manage DERs flexibly on the network to provide grid services that help address distribution system constraints, provide reliability, and defer and/or avoid network investments as NWAs, including via the development of a market platform to manage programs for DER to provide services to the distribution network.
- Help enable customer DERs to participate in the ISO-NE wholesale markets, including via FERC Order 2222, by deploying new technology to support the registration, review, and operational coordination processes for DER aggregations enrolling in the ISO-NE wholesale markets.
- Improve the interconnection process through enhanced transparency on network hosting capacity and enhanced capabilities to expedite interconnection studies.
- Enhance the customer experience and accelerate and enhance DER adoption.

This second wave of DERMs investments continues to deliver new features that support the Wave 1 investment objective to accelerate interconnection of DERs and introduces several new features to deliver a second objective focused around leveraging DERs to provide grid services (i.e., what technology platforms and features need to be in place so that DERs can reliably help the distribution network).

These new DERMs features are intended to support future customer programs described in Section 6.11, including expanding flexible connections to EVs, enabling virtual power plants with customer ES, and deploying more targeted usages of customer flexibility to alleviate network constraints.

c. FLISR Acceleration

Through the GMP, the Company was granted the funding to deploy FLISR to a group of high value feeders through 2025.

The distribution system is generally a radial design, meaning that if the flow of electricity is interrupted at one location, all customers electrically downstream of that faulted location are interrupted as well. Reliable distribution system design utilizes protective devices such as fuses, breakers, and reclosers to interrupt faults and limit the number of customer interruptions as best as possible for any given fault. In addition, switches are placed at strategic locations along a feeder and where feeders can be connected to another feeder, so that faulted sections of a distribution feeder can be isolated, and power can be redirected to customers in undamaged areas.

Fault Location, Isolation and Service Restoration (FLISR) is a control scheme that incorporates telecommunications and advanced control of key switching devices. This scheme provides remote monitoring and operator control of field devices for normal O&M, while at the same time providing an automated response to system contingencies. Automated feeder tie points and protective devices (i.e., advanced reclosers) are coordinated to isolate faults and restore service to unaffected sections of a circuit without causing thermal or voltage violations.

This automation scheme reduces customer minutes of interruption (CMI) for customers within the zone of protection, but outside of the fault zone. FLISR implementation also improves outage restoration time for customers within the faulted zone by enabling the system operator and control system to quickly locate and isolate a fault, allowing crews to begin and finish necessary field repairs sooner. Further benefits are detailed in the GMP. From a customer perspective, this means Company customers will experience fewer and shorter interruptions to their electric service.

As part of this ESMP, the Company requests funding scale its deployment of FLISR beyond 2025 where the benefits justify the costs across the service territory, so that a larger portion of customers can enjoy the benefits. Moreover, the Company proposes to accelerate its originally planned scheduled for FLISR deployment to deliver the reliability benefits of FLISR at scale sooner, given the pace of anticipated electrification of transportation and heating will drive the need for increased reliability.

d. CVR / VVO

Through the GMP, the Company was granted the funding to deploy CVR / VVO through 2025 to a group of high value feeders.

CVR and VVO are initiatives that use advanced technology to smartly control voltage regulation devices. The primary objective is to optimize the Company's power distribution, resulting in more efficient energy usage and minimized system losses. This not only leads to reduced demand and energy consumption for customers, but also offers financial savings due to reduced operational costs.

VVO technology flattens the voltage profile of a feeder by applying intelligent control to capacitors and regulators on the feeder which serves to minimize electrical losses, which allows the Company to lower the source voltage at the substation to provide energy savings for both the utility and the customer. Customer benefits are realized through reduced costs for electric energy and system capacity, which result in lower customer energy bills and lower emissions.

In line with industry best practices, the Company is also looking forward to integrating VVO/CVR with the ADMS. This integration will bring forth multiple advantages:

- Energy Conservation: With CVR, the Company aims to reduce the voltage slightly without compromising service quality. This strategy will lead to decreased energy consumption.
- Support for Renewable Energy: As more renewable resources like solar and wind energy are integrated into the network, ensuring steady voltage levels becomes pivotal. VVO/CVR will play a crucial role in managing the intermittent nature of these resources.
- Enhanced Equipment Longevity: VVO/CVR ensures that Company devices operate at optimal levels, thereby potentially prolonging their life and avoiding premature replacements.
- Superior Power Quality: VVO's role in reactive power control ensures that Company customers always receive power within the desired voltage range.
- Boosted Grid Visibility: Incorporating VVO/CVR into ADMS improves Company oversight of the grid's health, allowing us to address concerns promptly.

As part of this Future Grid Plan, the Company requests funding to accelerate and scale its deployment of CVR/VVO beyond 2025 where it is cost-beneficial across the service territory.

e. Future of Network Management Demonstration Projects

As part of this Future Grid Plan, the Company seeks funding to implement several technology demonstration projects critical to future network management capabilities.

The high-level theme of these projects is to validate the Company's ability to digitize assets and leverage that digitization to facilitate more dynamic (e.g., autonomous) data-driven management of the network. The overarching purpose is the Company's desire to identify transformational ways to better harness the potential of cloud technology and virtual assets on the network to improve the reliability of network operations and reduce the physical infrastructure footprint and associated costs for future ESMPs. That is, the Company will build new capabilities and test the bounds and feasibility of how far it can take software-induced network management to cost-effectively support traditional use cases on the network that would otherwise require expensive physical infrastructure, and to assess the feasibility of doing so. In testing these capabilities the Company will use a "test" and "scale" approach to uncover the necessary underlying technology and data architecture that would need to be deployed, as well as to lay the groundwork so to scale these capabilities to meet some of the anticipated distribution network management challenges and opportunities associated with high volumes of DER and electrification in the future.

In principle there are two major components that the Company intends to focus on:

- **Digitize the network and leverage those software-defined assets to reduce the physical footprint of the network**. For this the Company will explore the art of the possible with using dynamic management of digitized assets to meet different grid use cases (e.g., load management vs protection relays) -- which vary in terms of latency and other requirements -- and the accompanying technology infrastructure required to deliver on those use cases.
- **Push data computation and infrastructure to the grid edge**. As more assets are digitized on the network and more data is collected from devices located on the grid edge, data needs will continue to grow. The Company anticipates that there will be an inflection point where certain data management and analytics functions will be more fit for purpose to occur at the grid edge, rather than via centralized systems.

f. Communications

The communications investments proposed as part of the Company's Future Grid Plan include:

1. Requests for additional funding to scale and expand delivery of the network communications investments approved in the prior Grid modernization filing.
2. Requests for additional funding to implement enterprise network investments to deliver a more intelligent network

Scale and expand delivery of network communications investments approved in Grid Mod filing:

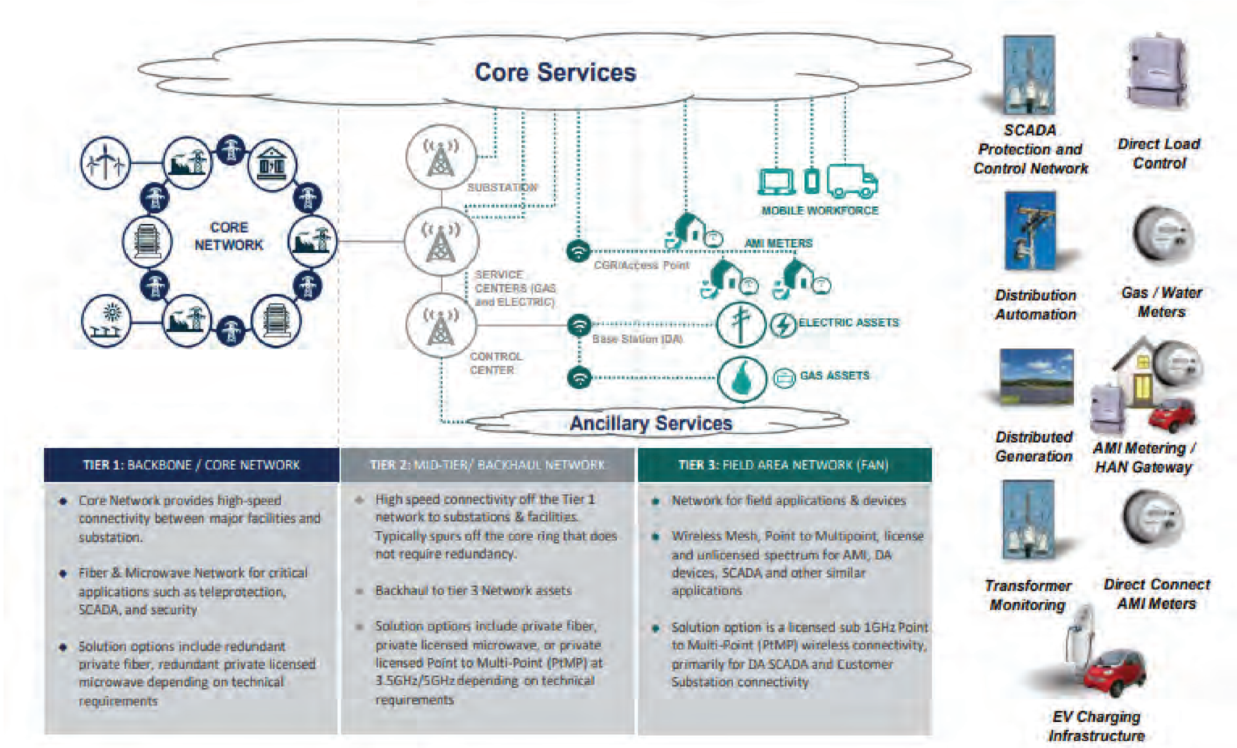
As approved in the GMP, the Company has initiated efforts to build and operate a private communication network, which will provide the majority of communications for the grid modernization investments and new distribution devices, including those supporting customer DERs. Transitioning from public to private network communications will result in greater network control and reliability, reduced long-term costs (e.g., avoid commercial cellular RTB costs that increase with every new grid device added), and better position the Company to accommodate the anticipated exponential growth in the number of endpoint nodes that need connectivity due to the increasing adoption of DG, EVs, and EHPs.

As part of this Future Grid Plan the Company is requesting additional funding to support the continued delivery of the communications network investments that have been initiated through the GMP beyond 2025. Delivery of the private communications network will result in a more reliable, secure, and cost-effective communications network that can more adequately support a more intelligent and DER-rich network operation for Company customers. The proposed expanded investment builds on similar activities described in the GMP, including delivery of:

- **Tier 1:** core network backbone consisting of leased circuits, private fiber, and private licensed microwave from which all data from Tier 2 and Tier 3 assets will traverse through into back-office systems.
- **Tier 2:** the mid-tier backhaul network of leased circuits, cellular, private fiber, private licensed microwave, and/or private licensed Point-to-Multipoint communication
- **Tier 3:** field area network (FAN), which extends connectivity into the realm of the distribution system, as well as remote transmission assets, so that advanced grid devices and DERs can be integrated with grid operations. The primary access of the FAN is wireless using a combination of commercial cellular and privately licensed spectrum, which offers the highest level of control, reliability, and security. The FAN supports the Company's plans to integrate remote sensors, advanced capacitor controls, line voltage regulators, state-of-the-art reclosers and circuit breakers, as well as connected DER devices with the distribution control center ADMS.

The relationship between core services, the tiers described above, and various other network devices is described in Exhibit 6.6 below.

Exhibit 6.6: Relationship between Core Services, Tiers 1-3, and Other Network Devices



Enterprise communication networks:

As part of the Company's Future Grid Plan, additional funding is being requested to deliver Enterprise networks to support the growing need to carry data, voice, and users to deliver on the proposed clean energy enabling investments. These investments align with the overarching need to deliver incremental and proactive capabilities and services that will ensure the collective networks operate in an efficient, secure, and reliable manner. These investments include:

I. SD-WAN

The Company is moving forward with implementation of a corporate-wide software-defined wide-area-network (SD-WAN) that will help to improve network performance and meet the current and future demands for network capacity and scalability in support of the large data-traffic volumes anticipated by the digital transformation. The main components of the upgraded WAN are the edge routers. Network traffic is routed through edge routers and sent to smart controllers for centralized orchestration of the routing policies, security, segmentation, and authentication of devices across the corporate network. This routing enables certain remote traffic to be re-directed to the cloud infrastructure instead of passing through the core on-premises infrastructure. The local-area-network migration to the SD-WAN improves traffic and data routing, security posture, and network performance for cloud-based applications.

The SD-WAN effort also includes a refresh of components within the secure telecommunications Internet gateway (STIG) at four data centers that help improve network reliability while reducing security and operational risks at the edge of the network infrastructure. The refresh supports security improvement efforts by adding new devices to the demilitarized zones and redesigning the Internet and core firewall structures. Ultimately, enabling core connectivity for data traffic transport and reduced data-traffic congestion.

II. Wireless LAN

Increasing demands for network capacity and speed in throughput necessitates scaling and upgrading core infrastructure. The need to support digital workloads, remote working, applications hosted in the cloud, end-user collaboration, and increased scale of wireless devices are some of the activities that drive an uptick in wireless density. Providing high-density and very high-density Wi-Fi to improve performance and coverage are two key upgrades needed to enable high bandwidth and usage-services such as voice and video (e.g., video surveillance at substations and other future use cases).

Amidst that modernization effort, the Company is moving towards a cloud-based centralized wireless local-area-network (LAN) control architecture with access into an internal simple cloud-management dashboard/portal (via the deployment of Aruba Central[2]) to provide increased visibility of the wireless traffic for improved monitoring, troubleshooting, and management, especially in support of control room and dispatch operations.

The shift from the legacy architecture into the cloud-based architecture eliminates the expensive specialized hardware-based controllers and greatly lowers energy consumption. Leveraging the cloud for management and control functionality brings 99.99% reliability and unlimited computing resources.

Complexity is decreased by removing the requirement for redundant hardware-based controllers, stacking controllers, clustering, etc. Client data is bridged at the access points at the edge where policies are enforced instead of tunneled to on-prem centralized controllers, thereby taking advantage of the local Internet breakout provided by the Company's SD-WAN architecture. Furthermore, security is improved with policies enforced closest to the source versus traffic entering deep into the network before being enforced.

The cloud-based architecture affords an ability to take advantage of modern Artificial Intelligence (AI) and Machine Learning (ML) features and functionality. The AI insights help to proactively “find the needle in the haystack” of data. The AI search (Natural Language Processing (NLP) search engine) and AI assist (auto traffic capture, auto ticket generation in IT Service Management (ITSM) platform), and auto Technical Assistance Center (TAC) escalation raise the bar in operational efficiencies.

III. Voice/Contact Center

The Company plans to implement several upgrades to its voice communications and contact center capabilities to 1) better serve as the trusted advisor in supporting customers as they participate in the clean energy transition, and 2) better equip the Company‘s operations teams for the increased network complexity challenges expected with a more DER heavy grid.

The Company is upgrading and modernizing the customer contact centers by migrating to a new platform primarily for voice. It will have additional AI capabilities for chat, interactive voice recognition, and integration with the Company’s web-based and mobile application capabilities for an improved customer service experience. This will become increasingly important as the Company expects contact center volumes to increase as more customers adopt electrification technologies, install DER, participate in new clean energy customer programs, and enroll in TVR. The Company intends to ensure adequate support as trusted advisors is provided to Company customers and to help educate them on new clean energy offerings.

The legacy private branch exchange (PBX) architecture in control rooms and dispatch are being replaced with IP-based telephony (IPT), which eliminates the operational risks of the legacy PBX

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[2] Aruba Central is a powerful cloud networking solution that offers simplicity for today’s networks." Either modify parenthetical to (via the deployment of networking solution Aruba Central) or remove parenthetical to simplify

devices and provides enhanced soft-phone experience for the system operators. The Company is also expanding the use of IP Telephony technology in substations to migrate off legacy phone system technology.

Voice analog lines are being consolidated and unutilized lines decommissioned, as well as performing a refresh all voice gateways. Cisco Unified Communications Manager (CUCM) which manages call processing, phone registration, and ensures seamless interoperability amidst various collaboration tools is also being upgraded for enterprise users.

The Company is also pursuing options to update the current Land Mobile Radio (LMR) infrastructure which is leveraged to operate, maintain, and restore the electric grid. The LMR infrastructure is used in the control / dispatch centers with mobile radio units installed in supervisor vehicles and distribution line vehicles. The critical infrastructure supports storm restoration and is a key component to ensuring appropriate field support for the flexible grid and grid services with the integration of DERs.

2. Metering and billing systems

a. AMI

The Company has already received authorization and funding for full deployment of AMI and is not seeking additional funding through the Future Grid Plan.

The Company has already begun to invest in some of the keystone systems that will enable the next generation of metering technologies, including standing up communication networks, data processors and management systems. Testing the technology and processes associated with generating value from AMI has also already begun.

When complete, customers will experience a wide variety of new functionalities, including a sampling of capabilities outlined in Exhibit 6.7 below. Note that this is not all of the customer-focused benefits that will be enabled by AMI.

Exhibit 6.7: New Customer Functionalities Enabled by AMI

Functionality	Brief Description
Near Real Time Customer Data Access	Customers will be able to view accurate, granular, and timely data associated with their usage through the online customer portal.
Customer Energy Insights	The Company will provide customers with insights into their energy use trends that they can use to lower their bills and environmental impact.
Green Button Connect	Customers will be able to provide third party vendors with access to their meter data to provide tailored insights and services informed by data.
Outage Detection	AMI meters will automatically send outage information to the control room to eliminate the need for customer outage reporting and reduce the time for service restoration.
Remote Electric Connect and Disconnect	The Company will be able to connect or disconnect new customers during the move-in and move-out process without the delay of sending a truck. This will enable day-of service restoration for and reduce delays associated with account or service changes.
Power Quality Monitoring	The Company will be able to monitor power quality, such as voltage, to ensure that the power delivered to customers is within the standards set by regulators and offer new tools to correct those issues when they arise resulting in higher customer satisfaction.

In the future, AMI will provide customers with enhanced understanding, choice, and control over their energy usage, enabling possible reductions in their total bill. The Company will leverage user friendly interfaces and messaging to provide customers with granular data about their energy use, along with strategic insights into what is driving their consumption so they can take action. To make proactive management of their energy use and bills more attainable, AMI will also make it easy for customers to provide that data to third party contractors if they choose to do so. Third party contractors may include qualified energy experts in the fields of EE, DR, solar PV, and ES who can design solutions, informed by data, that can reduce customers' energy consumption, bills, and environmental impact.

AMI meters also enable new capabilities in demand side management through passive and active methods like TVR and DR respectively. In the case of TVR, improved pricing signals, such as higher rates during times of high wholesale energy prices and distribution network load will encourage customers to shift their energy uses to off-peak times – lowering the total cost of service to all customers. AMI also enables new DR programs where the utility can sign customers up to participate in manual or automated programs to shift electricity-intensive processes to off-peak times. For example, utilities across the country have been leveraging electric water heaters – which are extremely efficient in storing off-peak heated water for on-peak use – with minimal customer impact or inconvenience.

In addition to the direct customer benefits provided by AMI, the meters, network, and data flowing from these systems will support additional capabilities, including outage detection, VVO, and CVR which will be implemented by ADMS, but are enabled by grid-edge sensors in the AMI system.

b. Time-varying Rates Billing Engine

A robust and flexible billing system is fundamental to achieving the clean energy transition. Utilities need to be able to implement and operate a set of new rates and pricing mechanisms to provide economic signals that align grid needs with customer flexibility (e.g., time-of-use rates, demand rates).

The Company's current billing systems have little ability to bill customers at rates that reflect both demand and energy usage or time-of-use. TVR are limited today primarily to large C&I customers. The Company's current billing system is not built to efficiently implement TVR at the scale required for residential customers in coming years to realize the benefits of new AMI-enabled rates. The Company has determined that a more flexible and modern rate engine external solution will provide the necessary capabilities to support an evolving billing and rates environment. This modular solution will be integrated with the Company's centralized customer information and billing platform (the "CSS system"), which will enable the company to offer new rates to customers that take advantage of AMI in a shorter time and with lower implementation risk. This approach has been successfully adopted by other utilities in the US.

As discussed in more detail in Section 6.10, the ability to bill customers efficiently for TVR is a critical enabler for delivering more accurately aligned bills based on cost causation and empowering customers with more control over their monthly bill. TVR will also be a critical component for managing load on the network and is a critical prong in the Company's strategy to better integrate flexible demand to reduce system peak. Relatedly, TVR may create additional economic incentives for customers to adopt flexible demand devices in their homes and businesses like controllable thermostats and behind the meter (BTM) ES.

As part of this Future Grid Plan, the Company is requesting additional funding to develop and deploy new billing system technologies that can support accurate billing and settlement for customers participating in future TVR and pricing structures.

3. Customers portals

a. DER Customer Experience Enhancements

The Company's Future Grid Plan seeks funding to leverage technology to improve the DER interconnection and electric connection processes, including improvements to the existing customer portal for DER interconnections. To accelerate the adoption of clean energy devices on the network (e.g., solar, ES, EVs, EHPs), the Company continuously looks for ways to reduce the manual steps and time required for submission, review, and approval of DER interconnections and beneficial electrification connections.

The DER preapplication process is a key focus for enhancing the customer experience for interconnection, and its improvement can help to avoid issues, delays, and inefficiencies in the project development process. Therefore, the Company will stand up a preapplication customer interface that will enable customers to work with their contractors to design their technology solution in the optimal way and take action to avoid system designs that will hold up their application or add additional costs in resubmission. It will be a guided questionnaire which will help customers, installers, and developers to research their proposed location and receive location specific information in real-time. In addition, this enhanced preapplication process will also be offered to electric connect requests, to ensure a unified and seamless connection process for all electric and interconnection requests.

The Company will add a connection schedule feature which will help provide visibility into the construction schedule on a granular level. The customer and the Company can share tasks, milestones, and discuss risks. By automating the residential application review and process, the Company expects that 90-95% of residential customers will receive same-day approval of their application to commence construction. By relying on machine learning, process automation, and other advanced review capabilities, the Company will significantly improve the efficiency of and customer satisfaction with the interconnection process

Furthermore, the Company anticipates more prospective and existing customers will apply for new services, which will increase the need for a newly improved preapplication process. In an effort to provide customers with insight into the Company's readily available capacity, the Company has made public a System Data Portal ("SDP").[3] The site displays hosting capacity maps and heat maps, along with other distribution data such as the Company's Distribution Planning Criteria and Annual Reliability Reports. Hosting capacity is an estimate of the amount of DERs that may be accommodated without adversely impacting power quality or reliability under current configurations and without requiring infrastructure upgrades. Heat maps are intended to help DER developers identify distribution circuits that are loaded to 80% or more of their summer normal feeder rating. The heat map is also intended to identify where additional capacity exists and can accommodate beneficial electrification, EVs and EHPs. These tools will be incorporated into the pre-application tool to make the connection and interconnection process as efficient as possible.

b. Clean Energy 2.0 platform

The Company's Future Grid Plan seeks funding to enable the development of the Clean Energy 2.0 (CE 2.0) platform. This is a new proposed technology platform to support the Company's implementation and delivery of various clean energy programs, including those related to energy efficiency, electric heat pumps, electric vehicles, and DR.

For the Company to continue delivering customer-facing incentives and programs to customers who elect to take part in the clean energy transition, a new technology platform is required to provide modern and sustainable capabilities for promotion, sales, fulfillment, delivery, and reporting of clean

[3] https://systemdataportal.nationalgrid.com/MA

energy products. The Company's current platform for demand-side management products, InDemand, an internally developed system that was designed and implemented beginning in 2003, is based on custom code and technology platforms that are approaching end-of-life and end-of-support. InDemand composed of fragmented architecture that lacks data uniformity, is labor intensive to operate and maintain, difficult to resource, provides a poor experience for employees, customers, and trade partners, and is costly. Further upgrades to the aged underlying technology supporting the InDemand platform would not be feasible without a complete re-development effort. Moreover, the platform in its current form only accommodates EE and EHP programs, but not EV or DR programs. In order to continue to deliver programs to customers at a pace and scale that will enable the Company to meet the Commonwealth's clean energy goals a new system will be required.

For the reasons stated above, the Company's Future Grid Plan seeks funding to enable the development of the CE 2.0 platform. The new technology platform will provide modern technology capabilities for promotion, sales, fulfillment, delivery and reporting of clean energy products and programs to customers in the Commonwealth. This software-as-a-service platform is best in class among utilities and comes preconfigured with the Company's most essential requirements. To accommodate fast evolving clean energy objectives and incentives, the system will have flexibility, self-service capabilities, and widely understood maintenance protocols.

Among other benefits, CE 2.0 will:

- Improve the implementation, tracking and reporting of program achievement.
- Reduce application and incentive payment cycle time, thereby enabling faster processing of incentives and rebates to customers.
- Improve the customer experience for the Company's clean energy products and increase customer adoption.
- Provide a transparent and seamless experience for trade partners.
- Improve collaboration, transparency, governance, and productivity for the Company's clean energy employees, enabling them to focus on value-added work.
- Reduce opportunities for fraud by avoiding manual data management intervention and increasing built-in governance and validations.
- Increase program speed-to-market.
- Increase operational efficiency by decreasing the use of paper documentation, reducing project delivery costs, and accommodating fast-evolving clean energy objectives and incentives.

4. Data

Data is in many ways the underlying "blood" that enables all of the transformational technology investments that are required to operate and plan a more dynamic, reliable, and affordable network for Company customers as described in this Section 6.3. The backdrop against the technology investments included in this Section 6.3 is that there is more data available today than ever (and there will be even more in the future), and that data is changing the art of the possible for how the Company can best serve customers, including how to communicate with customers, develop and offer new customer programs, connect customers to the network, and plan, build, and operate the network to power the lives of customers.

Maturing how data is captured and managed will need to be an ongoing effort that will be informed by new technologies, lessons learned and changing customer and stakeholder needs. The Company's path to increase customer choice, improve speed of DER interconnection, and enable more dynamic grid management to both accommodate and leverage the power of connected devices on the network via DERMs and AMI requires that the Company invests in multiple areas including people, process and technology. As described below some of these data investments are considered "foundational" investments for which the Company has already approved funding, and other investments are considered "net new" and required to support the envisioned future electric network as part of this Future Grid Plan.

Foundational data investments:

As part of the GMP, the Company has authorization to invest in the buildout of foundational data capabilities and will continue to expand and scale these data investments as part of the "core" expenditure. Therefore, the Company is not proposing costs for foundational data investments as part of its Future Grid Plan. However, they are described here briefly since they are critical to delivering the smarter network envisioned. Key features of the Company's foundational data investments include:

- **Data accessibility.** Data is available "when and how it is needed" via investments to centralize data from enterprise systems and other data sources to an electric data platform.
- **Data quality**. Data is of the right content and quality to support relevant business processes via investments in data quality management tools.
- **Data management.** Investments to develop and implement data stewardship, management processes, management, and security across data products.
- **Data interoperability.** Ensure data can be related across all domains via a "One Model" that functions as the single source of truth on which authoritative sourcing, data governance, and data quality are based. Modernize asset and connected network model extracts from GIS to both geospatial and tabular formats.
- **Data insights.** Decisions and actions are data-driven based on the development and delivery of reports and dashboards to deliver insights to support grid modernization and other business processes.

New Data Investments:

As part of this ESMP, the Company requests funding for incremental data investments to support the further integration of DER onto the distribution network, including preparing the Company to reliably operate a more dynamic distribution network.

a. Intelligent Data Capture:

Building upon the foundation data enhancement work, the next phase of the Company's work will be focused on how data is acquired and assured, leveraging an investment called intelligent data capture.

Electric network operations and planning are becoming more and more reliant on timely, accurate and ever more granular data. Network management technologies like ADMS, DERMS, FLISR all rely on data, and their potential to deliver more benefits at scale hinges on their ability to analyze, draw insights, and inform action based on faster and more granular data. At its core, data needs to be captured digitally. The Company has existing efforts that are helping facilitate data capture, particularly the advent of AMI, which will introduce massive amounts of new data to inform both Company network operations and improve customer experiences. However, achieving the full vision of data-driven network planning and operations requires integrating data from various sources and capture techniques to ensure the Company has the insights it needs to integrate and manage increasing DER.

The Intelligent data capture investment will leverage ML and AI to model, compare and correct data based on aerial and ground based light detection and ranging (lidar) and photogrammetry. This, in conjunction with asset data, customer data, network models and sensor data will allow the Company to provide data to ADMS and other tools to better understand, efficiently maintain and operate the Company's network in an ever-changing configuration and conditions.

b. Grid Asset Data Enhancements:

The Company's foundational data investments are a critical starting point, though further investment will be necessary to achieve the full data capabilities required to support future electric network planning and operations use cases. The outcomes of this work includes fully digitized data processes, better leveraged AMI data in Company planning processes, better data to support DER digital product investments and empowering greater data driven decision making. Additionally, the Company will continue to drive data interoperability and facilitate wider availability and use of data, increasingly blurring any lines between informational technology (IT) and Operational Technology (OT) where critical to deliver positive customer outcomes.

This investment will focus on:

- Delivering additional value from the Company's data platform & "One Model" by incorporating additional data sources to further enable business processes and tools.
- Continuing to mature the Company's data analytics and reporting capabilities, incorporating new tools and techniques - identifying opportunities to deliver more efficiently for Company customers. This includes ensuring that data catalogs and other metadata stay fit for purpose to enable ease of data discovery, sourcing and use.
- Invest in people and data management capability by hiring additional personnel to deliver data focused outcomes and embed data management stewardship within each area of the Electric Business.
- Implement a Master Data Management tool to ensure that key business and operational data is mastered and synchronized across the Company's enterprise systems from the authoritative "One Model" to assure that all processes are using the best data available.

5. Asset planning, management, and work execution

The Company is deploying new digital products across a variety of areas to transform the efficiency and effectiveness with which the Company plans, designs, build, and operates the electric network. The Company seeks funding as part of this Future Grid Plan to develop and deploy these technologies, which will be critical to the Company's delivery of an electric network capable of supporting the Future Grid Plan objectives for DER and electrification adoption, and reliability and resiliency of the network. Using the SAFe framework for digital product delivery (see description in 6.3.1), the precise details and delivery mechanisms for each product, as well as the prioritization of specific product efforts relative to each other, may shift based on highest identified need. Thus, the Company discusses future digital product efforts thematically in this section and focus on features that it expects to deploy, as well as expected customer benefits.

a. Planning the Network

To support the way the Company plans the network, the Company is deploying new digital products focused on how the Company identifies, designs, and scopes required network investments. The rapid pace of anticipated electrification and the uncertainty of how, when, and where load will grow across the network introduces novel challenges to the way that the Company plans the network. This increased complexity in network planning is only heightened by the increased reliance on the electric network as more customers depend on electricity for their heating and transportation needs, and the network encounters increased frequency and severity of extreme weather events. Further, the electrification of the transportation and heating sectors more broadly introduces a new set of stakeholders with whom the Company has not had to historically co-plan (e.g., Mass DOT on highway charging, gas utilities for decarbonization of heat).

New digital products that may aid in identifying, designing, and scoping network investments include:

- New integrated electric and gas planning tools to facilitate the co-planning across gas and electric networks required for an orderly decarbonization of the heating sector (see Section 11);

- Deploying more intelligent, and partially automated engineering design work to expedite the planning process;
- Using historical data and predictive analytics for forecasting across projects and workplan;
- Visualization of the entire end-to-end project and program workflow to highlight and resolve workflow bottlenecks; and
- Condition-based and predictive maintenance so assets are fixed just ahead of failure to drive a more resilient network to meet increasing customer expectations and reduce cost.

The resulting benefits from these products will include:

- More robust network infrastructure decisions due to faster and more automated planning processes that will enable multiple scenario analyses. This is particularly important given the uncertainty in future load growth.
- More tactical and proactive buildout of electric network infrastructure to support pockets of electric heating and transportation based on integrated planning with non-electric sector partners.
- Customer bill savings due to a more orderly transition from gas heating to electric heating.
- Customer bill savings from right on time investments that help stretch asset life.
- Reduced customer outages from failed equipment.

b. Operating and Managing the Network

As more customers adopt EVs and EHPs, customers' dependency on a reliable and resilient electric network will further increase. In addition to FLISR, whose continued deployment will vastly improve the Company's outage management and restoration strategy, the Company proposes to deploy new digital products capable of helping better prepare for major events and right size and accelerate the Company's response to network damage.

These products may include:

- New prediction tools that draw insights from weather data, prior storm data and experiential inputs to "right size" response resource needs during storms.
- New tools and processes to perform rapid damage assessment, including collecting information from multiple data sources such as drones and synthesizing those data insights to more precisely deploy crews based on identified damage.

The resulting benefits from these products will include:

- Faster restoration times and reduced customer interruption minutes.
- Customer bill savings by leveraging technology to supplement and/or reduce the need for on the ground damage assessment, particularly in difficult to reach locations, and thereby reducing operational costs.
- Safer outcomes for storm response crews and impacted customers due to more right-sized and proactive deployment of storm response crews ahead of major events.

c. Building the Network and Executing Work

The Company is committed to helping the Commonwealth achieve its Net Zero goals by accelerating customer adoption of electrified heating and transportation and the connection of DERs to the network. As Sections 6.5 – 6.10 highlight, to deliver an electric network to supports these goals requires a significant amount of physical infrastructure buildout, including numerous complex and concurrent multi-year substation projects. We are prepared to meet these challenges with the support of new digital products to streamline the efficiency of existing processes across the work execution lifecycle, including permitting, scheduling, supply chain management, resource management, onboarding, and every step along the way.

These products may include:

- Real-time status visibility, routing, and automated notifications to ensure right materials, equipment, people are in place and ready before a job begins via a dynamic work scheduler.
- Integrated single view of all right of ways (ROW), assets, construction, work in area, environmental, customer/property owner interactions, etc. to streamline the end-to-end process.

The resulting benefits from these products will include:

- Faster delivery of critical network infrastructure projects to keep pace with load growth from electrification. Automated and digitized work scheduling, preparation, and execution will increase field productivity to meet the rising volume of work (i.e., new connections, infrastructure build-out and maintenance) while maintaining cost efficiency on behalf of customers. This will be critical to ensure that the Company can build out the network quickly and cost-effectively and accelerate capital delivery wherever possible to keep up with the anticipated pace of electrification and DER adoption.
- Reduced likelihood of equipment overloads during build out period. As discussed in Section 6.4 through 6.10 where the proposed network infrastructure investments are described, there are several instances when the expected project implementation date may exceed the forecasted “need by date,” resulting in a gap period where equipment may overload during peak hours. Faster project delivery made possible by work execution digital products will help mitigate this risk and reduce the likelihood and severity of potential overloads.
- Customer bill savings resulting from more efficient management of workforce operations utilizing digital tools to lower operating costs.

6. Security

Physical and cybersecurity to protect the distribution network as increasing numbers of grid modernization devices are added to the system are critical to managing the distribution system safely and reliably. We expect greater cyber and privacy threats to emerge as new, grid connected technologies are introduced to the network. Monitoring and control capabilities must proactively include physical and cybersecurity solutions into distribution network designs and processes rather than reactively as a retrofit or after-thought.

The risk from cybersecurity is increasing because:

- Greater complexity increases exposure to potential attackers and unintentional errors.
- Although there are associated benefits with linked networks (including data consolidation and improved visibility), networks that link more frequently to other networks introduce common vulnerabilities that may span multiple systems and increase the potential for cascading failures.
- More interconnections present increased opportunities for “denial of service” attacks, introduction of malicious code (in software/firmware) or compromised hardware, and related types of attacks and intrusions.
- As the number of network nodes increases, the number of entry points and paths that potential adversaries might exploit also increases.

- Increased data gathering and a shift towards two-way information flow increases the potential compromise of data integrity and confidentiality of data, resulting in potential data breaches, customer privacy intrusions or system compromise.

The Company is actively working to mitigate these highlighted potential risks to ensure the distribution system is as reliable, safe, and cost-effective as possible.

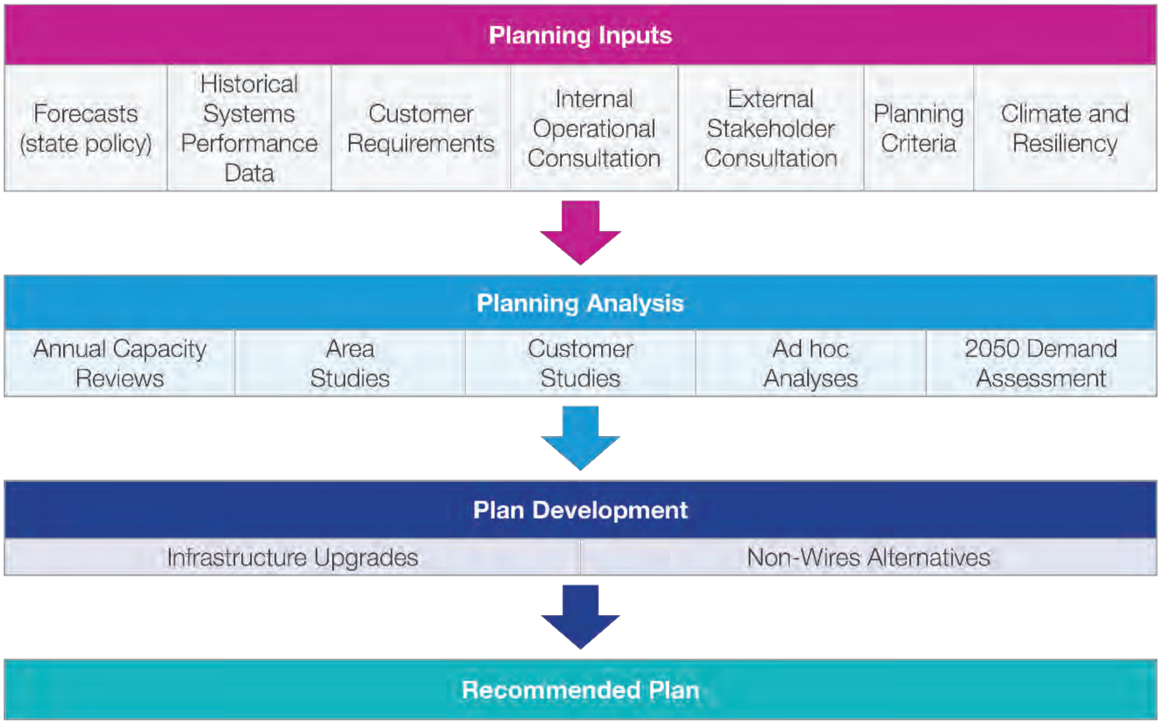
As part of the Company's Future Grid Plan, the following incremental investments are being proposed to support enhanced cybersecurity concerns associated with the various changes the Company expects on the network related to the clean energy transformation. The Company has forecasted its security investments for each year to directly support the technology investments proposed in this Section 6.3. This will ensure that the network will be prepared for the specific incoming integrations and that any potential risks are managed safely and securely.

- **Device management** including effective network authentication and management, which will become increasingly important as the volume of connected devices exponentially increases. This also includes encryption (i.e., hardware vs software, speed, patch-ability) of data at rest, and in transit for "internet of things" devices.
- **Network convergence** including network security and communication protocols to integrate IT and OT, which will be become critical in instances where the segregation of the two is no longer appropriate.
- **Penetration testing**, including threat detection models and security testing, security operations, monitoring and response.
- **Security Orchestration Automation & Response (SOAR)**, which includes the ability to detect, mitigate and respond to security events through improved visibility, orchestration, automation, and data analysis.

6.4 Planning Sub-Regions

As described in more detail below, the Company's Future Grid Plan analysis builds on the existing and robust planning process (i.e., Annual Capacity Reviews and Area Planning Studies) that the Company uses to identify infrastructure upgrades and other investments needed to continue to ensure a safe and reliable distribution system. The overall process of developing the Company's investment plans is described in Exhibit 6.8.

Exhibit 6.8: Plan Development Process



1. Annual Capacity Review

Capacity reviews are completed annually. They identify imminent thermal capacity constraints and assess the capability of the network to respond to contingencies. The actual observed feeder and transformer peak load values from the prior year, adjusted per the forecast, are the basis for the capacity reviews performed by the Distribution Planning & Asset Management (DPAM) team. The capacity planning process includes the following tasks:

- Review historic loading on each sub-transmission line, substation transformer, and distribution feeder.
- Apply and evaluate impacts of the weather adjustment and econometric forecast on future peak demand growth as per the Electric Peak (MW) Forecast.
- Analyze forecasted peak loads with comparison to equipment ratings.
- Consider system operational flexibility to respond to various contingency scenarios.

As part of this process, growth rates from the forecast are applied to each feeder and sub-transmission line in each area. Specific feeder, sub-transmission line, and/or transformer forecasts are adjusted to account for known spot load additions or subtractions, as well as planned load transfers due to system reconfigurations. Feeder/substation forecasted peak loads under the extreme weather scenario are used to prioritize and inform planning studies and to determine if the thermal capacity of facilities is adequate for future load level projections.

Individual project proposals are identified to address any imminent planning criteria violations. At a conceptual level, the Company prioritizes these small-scale project proposals and submits them for inclusion in future year capital work plans.

2. Area Planning Studies

Area Planning Studies are comprehensive reviews of the applicable study areas within the Company's service territory that result in long-term infrastructure development recommendations with defined project scopes to solve system issues identified over a 10-to-15-year period. Area Planning Studies enhance the ability to meet obligations to provide safe, reliable, and efficient electric service for customers at reasonable costs.

The Company typically does an area planning study for a given study area every five to seven years. However, timing may change based on various system assessments that inform the prioritization of future studies. In particular, Annual Capacity Reviews assist in prioritization of Area Planning Studies. Areas with more normal and contingency overloads might be prioritized over areas with fewer issues identified in these Annual Capacity Reviews.

Area Planning Studies are detailed, multi-step assessments that take several months to implement. The Area Planning Studies consider all aspects of the needs in the targeted geographical and electrical area, including but not limited to all Distribution Planning Criteria violations, operational needs, external stakeholder consultation, and customer requests.

Area Planning Studies include the following stages:

- Stage 1: Definition of electrical and geographical scope of study and gathering necessary data needed to execute the study.
- Stage 2: Initial system assessment consisting of a quick analysis of facilities and system performance within the identified study geographic and electric scope.
- Stage 3: Study kick off meeting held to inform the larger stakeholder group that an area planning study is underway and to solicit input from those with knowledge of the system infrastructure in the area under review.
- Stage 4: Detailed system assessment and engineering analysis.
- Stage 5: Development and project estimating of alternative infrastructure and NWA plans.
- Stage 6: Review of various alternatives' relative costs and benefits and identification and finalization of a recommended plan.
- Stage 7: Technical review of the recommended plan by internal stakeholders.
- Stage 8: Delivery of area planning study report documentation upon completion of the study.
- Stage 9: Sanction of any recommended projects having forecasted spending within the next three fiscal years.

Additional planning activities performed by DPAM include but are not limited to:

- DG System Impact Studies
- Large new customer load request reviews
- Review of acute reliability and other system performance concerns
- Operations and Control Center support
- Arc flash/fault duty customer requests

3. The Future Grid Plan (ESMP) Analysis

For the Company's Future Grid Plan, the Company conducted engineering analysis for three planning horizons: 5-year (2029), 10-year (2034), and 2050 based on the electric peak forecasts produced by the Company's Electric Load Forecasting team as described in Section 5. This process applied the forecast across the Company's distribution system to evaluate the impacts of the forecasted adoption of electrification and DERs on the electric distribution network. Sections 6.5 – 6.10 contain the recommended scopes of work to address capacity deficiencies identified through this Future Grid Plan engineering analysis.

The analysis considered the future loading of major distribution equipment, primarily substation transformers, and the capacity increases that will be necessary to support the forecasted load. The Company identified loading concerns emerging at substation transformers where the load on a transformer is forecasted to exceed 100% of normal equipment ratings and sized appropriate solutions to address the projected overloads. The Future Grid Plan engineering analysis assumed that infrastructure upgrades already included in Company's core network investment plan (described above), investments in the pending CIPs, and investments required to interconnect certain DG (i.e., solar PV and ES projects) already in the group study process would all be in place. As such, the infrastructure investments identified from the ESMP engineering analysis are incremental investments needed to deliver on the Commonwealth's clean energy objectives and assume that those other infrastructure investments are also made.

In addition to substation transformers, the Company also identified normal loading constraints on its distribution feeders by comparing projected feeder loads against the applicable rating. Where forecast load growth caused equipment to exceed its ratings, the Company identified scopes of work to augment distribution capacity.

The Future Grid Plan infrastructure investments described in Sections 6.5-6.10 were determined to address projected asset overloads resulting from forecasted load growth associated with electrification of transportation and heat. However, as the Company invests in network infrastructure to expand its system capacity, these same investments will also address other primary goals of the Future Grid Plan. Specifically, these investments create hosting capacity to support more DERs like solar PV and ES, and they improve reliability and resilience. Given the planning horizons (namely 2035 and 2050) and the scope (entire service territory at once), the Future Grid Plan engineering analysis focused primarily on normal capacity planning for major assets (i.e., substation transformers and distribution lines) using representative analysis to compare projected loads to asset ratings. Where available, the Company incorporated additional consideration of the following secondary drivers in the development of scopes to address the primary loading need:

- Contingency loading
- Asset condition
- Reliability and resiliency
- Protection and arc flash
- Safety and health

Reliability and resiliency will be improved through the execution of these plans through the implementation of the latest Distribution Construction Standards. Distribution line scope development considered opportunities for the implementation of hardening methods such as spacer cable installation and expanded underground infrastructure where applicable to address resiliency considerations. Substation investments that are at locations which the Company's ongoing Climate Vulnerability Assessment have identified as a high risk of coastal flooding have incorporated flood mitigation considerations in the scope development.

This planning process allowed the Company to develop plans to increase capacity where it is forecasted to be needed to support the Commonwealth's Net Zero goals, primarily through major substation construction projects that typically take 5-10 or more years to execute.

Because the Company took a long-term view of the investments required, it was able to anticipate the system needs for electrification forecast to occur beyond a typical 10–15-year study horizon. The investments included in this plan are prioritized based on forecasted demand, known and anticipated system capacity and operational needs, and customer expectations and requirements. Absent this long-term vision, the Company in many instances would have needed to make successive investments in an asset or area, to react to electrification load growth and clean energy deployment, as it materialized. This approach would result in less cohesive solutions, and delays in meeting customer and community needs. Instead, through this plan, the Company is proposing a smarter, more efficient approach with more anticipatory investments scaled to the needs of an electrified and decarbonized Commonwealth.

For each project in the Company's five-year plan, it has been identified whether the project is anticipated to be achievable within a typical five-year execution schedule or if there are significant project dependencies or complexities that extend that duration. Examples of such dependencies include major transmission line extensions required to supply the expansion of an existing or the construction of a new substation, property acquisition for new substation sites or transmission lines, and significant prerequisite distribution line construction such as widescale conversion from a lower voltage (e.g., 4.16 kV) to a higher voltage (e.g., 13.2 kV or 13.8 kV). Consideration of project execution timelines and the first year of overload addressed by an investment influenced the investments which are proposed for implementation by 2030 or by 2035. Those projects with generally lower complexity and risk were considered more feasible for completion within the first five years, and other projects, particularly those with more substantial transmission dependencies and/or land acquisition and siting needs, were generally of higher complexity and risk and were forecasted to extend out into the 5–10-year horizon and beyond. Execution risks and the methodology used to develop a delivery plan are also described in Section 7.1.1.

Note that the plans proposed herein are triggered by specific projected asset loading levels and correlated to a need date based on the forecast. The pace and scale of electrification achieved in discrete geographic areas may result in the acceleration or deferral of specific investments to maintain alignment with the actual load growth experienced throughout the Company's service territory.

As part of its annual capacity reviews, and in each subsequent 5-year ESMP filing, the Company will reassess the projected load growth to consider recent actual performance and the latest forecast updates and reprioritize the investment portfolio appropriately. During each year's capacity review, the implementation schedule of large projects recommended through Area Planning Studies is assessed and adjusted if conditions indicate an adjustment is needed. This process validates and confirms the need date and implementation schedule of capacity related projects. In addition to annual forecast revisions, the scope and timing of specific investments may be influenced by other emergent factors such as load and DER customer spot loads and developing distribution system optimization capabilities.

a. Enabled Capacity:

All projects proposed through this Future Grid Plan increase capacity in areas where projected overloads have been identified. In the sub-region specific sections below, tables are provided summarizing the proposed projects, which include estimates of the MW capacity enabled for each substation project based on the substation transformer rated capacity. The tables also include several distribution-feeder-only projects (i.e., projects that do not involve new substation transformers). However, because distribution feeder capacity is more geographically dependent on the emergence of load patterns including spot loads, distribution capacity estimates for the feeder projects are not included. These projects do enable capacity and address projected overloads due to electrification load growth; this capacity is just enabled at a more local level that cannot be as easily aggregated to the community or sub-region level as substation capacity. Therefore, for the projects which address only distribution feeder capacity deficiencies they have been labeled as "NA" for "MW of enabled capacity" in the tables included in sections 6.5.1 – 6.10.1 for each sub-region below.

b. Non-wires Alternatives:

Approach to non-wires alternatives:

The Company defines NWAs as the use of a non-traditional solution to a specific electric network constraint or issue that defers or removes the need to construct or upgrade specific components or reduces the operational risk related to a specific network constraint on the distribution and/or transmission system.[4] NWAs could comprise ES, solar PV, localized DR, localized EE measures, or new flexible interconnection technologies depending on the characteristics of the distribution system need and available technologies.

The Company has developed guidelines for the consideration of NWAs in the distribution planning process that are incorporated into Area Planning Studies. The goal of these guidelines is to develop a combination of "wires" solutions and NWAs that solve capacity deficiencies in a cost-effective manner, factoring in the potential benefits and risks. The Company screens investments for suitability for NWAs as part of its standard planning procedure based on the project type (e.g., load growth or reliability), cost of the traditional wires project, and anticipated construction start date.

As part of this Future Grid Plan, the Company has considered a broader set of investment alternatives and use cases for NWAs, including the following:

1) NWA ("Avoided Infrastructure") - in this NWA use case, non-traditional solutions sufficiently reduce peak demand or increase peak supply in a given location to avoid the need for a planned wires investment altogether or at least until outside of the planning time horizon. These NWAs are more applicable during a period of relatively stable demand or slow demand growth as seen during the prior 15 years.
2) NWA ("*Bridge to Wires*")[5]– this NWA use case is more applicable to the long period ahead of accelerating demand growth from beneficial electrification, and this use case has two variants. In the first variant, an NWA can defer the date by which the Company would otherwise have deployed a wires solution to address a need. In the second "bridge to wires" NWA variant, the Company is faced with an imminent need for a capital project, but that capital project cannot feasibly be delivered in time to address the need. In this case, the "bridge to wires" solutions can be deployed quickly to reduce peak demand or increase peak supply to help mitigate the costly risks that emerge during that gap period when overloads on the network may be expected during peak hours (e.g., potential for curtailing service to customers, increased risk of outages and emergency equipment replacement).

With the scale and pace of projected load growth due to electrification, as part of the Company's Future Grid Plan, instance have been identified where an NWA is suitable to support the long-term needs of the distribution system (i.e., "avoided infrastructure" NWAs). However, the Company has identified that near-term strategic deployment of "bridge to wires" NWAs may help address areas in which project execution considerations lead to a projected in-service date for upgrades that occurs several years after the area's projected loading concerns first appear. These "bridge to wires" opportunities are described in the NWA section for each sub-region which follows, where the use of a non-wires solution can reduce the risk of impacts from overloads in instances where there are significant constraints to the expedited delivery of capital.

Put simply, the "bridge to wires" solutions are critical to ensure that a safe and reliable network can be maintained as the Company keeps connecting EVs and EHPs at pace while the network is still being built.

The implementation of the "bridge to wires" solutions can take many forms, including the active

[4] https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/What-is-an-NWA
[5] "Bridge to Wires" is a recent term of art for certain NWA use cases that the Company credits to Consolidated Edison in New York.

management of customer flexible demand devices such as EVs, controllable thermostats, and battery storage, and can be aggregated together as VPPs or provided via a flexibility marketplace. The success of these solutions hinges heavily on the Company's continued development of its DERMs investments (as well as other enabling technologies described in Section 6.3), which will establish the underlying technology foundation for the Company to effectively procure, track, forecast, dispatch, and communicate with flexible devices, so that they can be reliably counted on to deliver grid services based on the network constraints unique to their respective section of the network. DERMs will provide the underlying technology, but the Company will also progress its customer facing programs (as described in Section 6.11) to create compelling and convenient customer offerings that compensate customers appropriately for the flexibility services that they offer to the grid. These customer programs will leverage the DERMs technology investments to deliver services to the electric network that will transform the way the Company plans and operates the network.

The Company is relatively nascent on its journey with NWA, particularly with respect to the "bridge to wires" projects, and thus, intends to use this ESMP to build and test the Company's capabilities to successfully deploy these projects in a few prioritized areas. As the Company gains experience with non-wires projects, it will have a more accurate and informed understanding of how to best deploy these projects and how they can best be leveraged and scaled to support network planning and operations processes and accelerate the deployment of clean energy technologies across the network.

The technology investments discussion in 6.3 and the customer programs discussion in Section 6.11 describe the enabling technology and customer programs needed to help realize these NWAs. Below the key regulatory enablers to support NWAs are described.

Regulatory framework for non-wires alternatives:

As the Company embarks on its journey to establish new innovations for NWA, specifically the "bridge to wires" projects, the establishment of a strategic regulatory framework becomes crucial. In the first five years of the Future Grid plan, the Company intends to build, test, and successfully deploy NWA demonstration projects within select priority areas. During this period, the Company anticipates developing an accurate and informed perspective on the optimal deployment and ways to scale such NWAs to bolster network planning, operational processes, and the acceleration of clean energy technologies across the network.

Given the projected timing and pace at which the Company will need to increase electricity network capacity, largely to enable electrification load growth, the Company requests the Department grant the Company flexibility to investigate alternative solutions such as "bridge to wires" NWAs. Historically, when a capital project cannot feasibly be delivered in time to address the need, the need would be addressed with temporary measures like short-term load transfers or spot generation deployment. However, the NWA pathway offers alternative solutions that could be beneficial for customers. If approved, the Company intends on developing pilot projects for NWA opportunities that will develop and demonstrate a framework to compensate DER for providing locational grid services, including mechanisms to increase the value of DER deployed for these purposes. The primary goal of this would be to find alternative solutions that would reduce costs to customers and maintain an acceptable level of reliability on the system.

The Company is asking the Department to allow the Company to establish a $36 million DER Grid Service Compensation Fund to incentivize both FTM and BTM DERs that could be used as "bridge to wires" NWAs (described further in Section 6.11). The fund would also cover incremental administrative costs of running the program and assessing the potential for the NWA alternatives. For the next five years, if the proposal is approved, the Company would recover DER Grid Service Compensation funding up to the aforementioned budget cap via the cost recovery mechanism approved in the Company's forthcoming distribution rate case. The funds would only be collected from customers on an as-needed basis.

In order to use the DER Grid Service Compensation Fund for a specific project, the Company will demonstrate that an NWA opportunity satisfies at least two, preferably more, of the following Future Grid Plan (ESMP) statutory objectives that were initially described in Section 2.0 and that it creates net benefits for customers:

(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 sub-limits under chapter 21N.

Getting started deploying NWAs via a DER Grid Service Compensation Fund is essential to accelerate the deployment of NWAs.

Policy & Regulatory Enablers for Realizing Future Grid Plan Benefits

Policy and regulatory changes will be essential to realize the clean energy, reliability, and customer benefits from the Company's Future Grid Plan. There are policy and regulatory changes important to the Commonwealth's clean energy transition. While several such policy and regulatory changes are discussed in more detail throughout the Future Grid Plan, they are summarized here.

We have identified priority areas where action is needed:

1. **Timely cost recovery for electricity network investment (as discussed in 7.0)–** cost recovery mechanisms must be sufficient to ensure that network investment necessary to prepare the network for a reliable and resilient energy system that is capable of supporting beneficial electrification and renewable energy integration, including necessary incremental anticipatory investment to support expected demand. As part of the distribution rate case that will be filed in MECO in the fall of 2023, the Company will be proposing a cost recovery mechanism that enables the company to make the level of investment for the first 5 years of this plan. If approved by the DPU, this cost recovery mechanism will permit the company to make the needed core and incremental investments as described herein to achieve the Commonwealth's net zero goals. This proposed cost recovery mechanism is similar to what is already in place for MECO's incremental Grid Mod investments and will permit the timely recovery of any O&M and in-service capital investment up to a cap, subject to a prudency review in the year following the spend.
2. **Siting and permitting (as discussed in 7.3) –** As discussed in this report, the magnitude of work required to meet the Commonwealth's goals and to deliver the required volume of projects is significant and unprecedented, and will be challenged by current timelines for project siting and permitting. Reforms to existing processes should streamline siting and permitting for clean energy infrastructure to reduce lead times for electric infrastructure projects while placing community engagement at the forefront.
3. **Time-varying electric rates (as discussed in 6.11) –** Regulatory support for AMI-enabled advanced rate designs will be essential to enabling customers to provide customers with the opportunity to manage their energy usage in a way that allows them to manage their energy bills

while also limiting growth in total energy system costs. For example, advanced rates can encourage customers to avoid energy use during high-cost times, reducing total system energy and generation capacity costs. Innovative rates can also encourage also encourage more efficient utilization of the distribution and transmission systems, reducing the overall level of network investment needed in support of the transition.

4. **Flexible demand and non-wires alternatives (as discussed in 6.11) –** In addition to time-varying electric rates, new regulatory frameworks and policy support are needed to support development of customer offerings and NWA that can reduce the magnitude of demand growth from electrification and to mitigate or avoid local system constraints. Potential offerings to enable demand flexibility include expanded managed charging, and utility or third-party management of heat pumps and behind-the-meter storage. Regulatory and policy frameworks will be necessary to enable aggregation of the above in support of NWA that reduce the pace and scale of electric network build out and/or reduce the likelihood or severity of overloads on the network. Regulatory and policy frameworks must provide for sufficient compensation to encourage these resources and also establish rules for market participation.

5. **Integrated energy planning (see Section 11) –** Integrated energy planning (IEP) will be essential to achieve the decarbonization goals and mandates of the Commonwealth while providing gas and electric customers with safe, reliable, and affordable service during the transition. An orderly transition to decarbonization that includes coordination and collaboration on gas and electric system planning and customer demand-side programs outside of traditional measures offers several potential solutions to optimize overall energy system costs and reliability but will require unprecedented coordination and information sharing across EDCs and LDCs. A critical near-term step is the establishment of a gas and electric coordinated planning working group with representatives from the different Commonwealth electric and gas utilities, DOER, AGO, and key affected stakeholders (e.g., environmental, consumer). IEP 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, which will require development of new regulatory frameworks.

6. **Prioritizing affordability, equity, and justice for all communities in the energy transition (to support EJC outreach strategy in Section 3.3) –** Multiplate policy and regulatory actions will be necessary to support an equitable clean energy transition. These include**:**

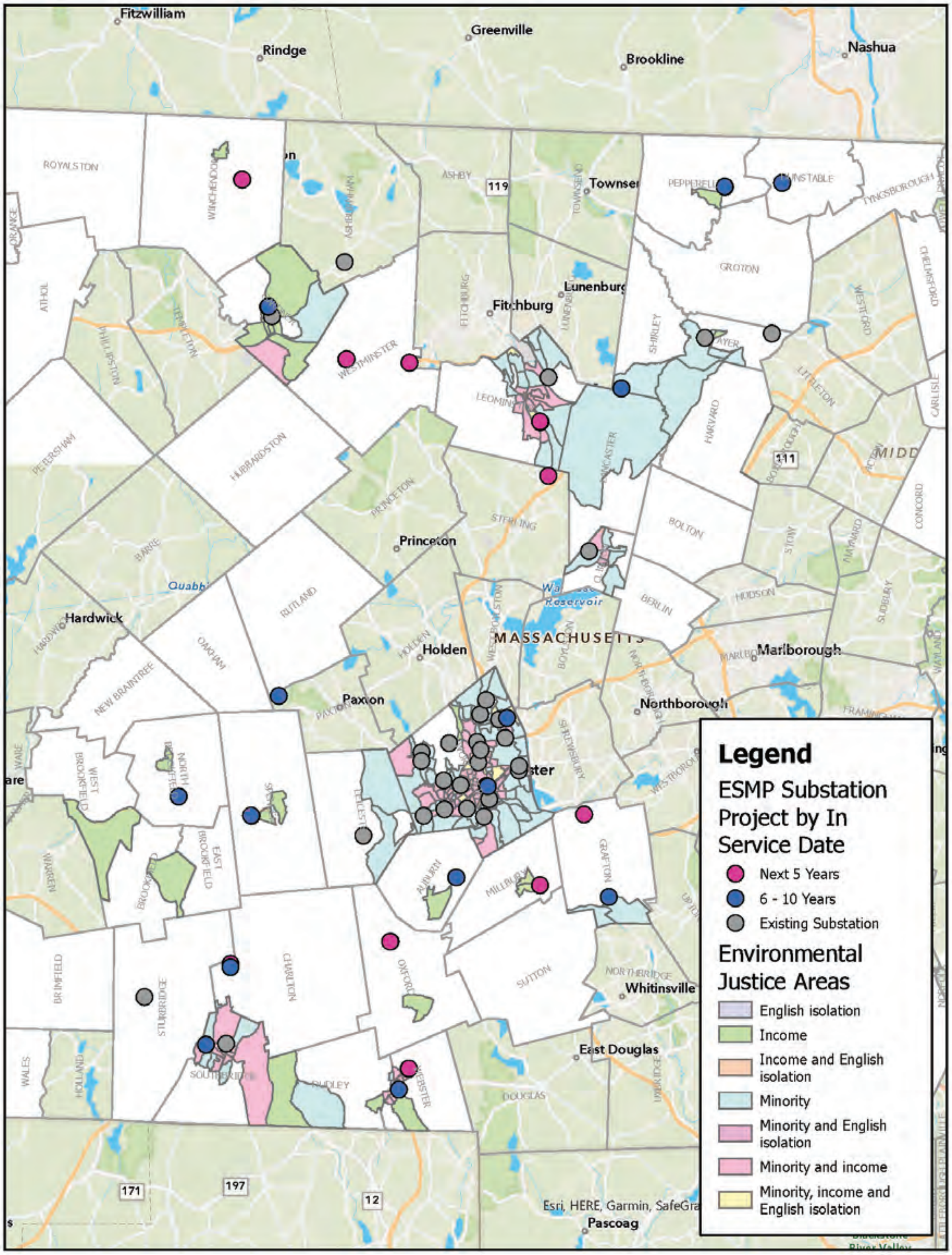
- Funding for expanded assistance programs and low-income bill discount programs, and customer outreach to support participation in such programs;
- Collaboration with utilities and community stakeholders to ensure effective outreach to customers and communities in initial stages of infrastructure and utility program development to develop awareness of forthcoming proposals and identify community priorities and concerns;
- Reforms that support the ability of customers in environmental justice populations, especially low-income customers, to participate in customer programs.
- Enhancing access to regulatory and policymaking processes in support of more equitable project and program outcomes; and
- Funding to support collaborative efforts to encourage a diverse clean energy workforce; and
- Collaboration with utilities and stakeholders to develop meaningful metrics that support objectives of increased access, engagement, and realization of program benefits in environmental justice communities.

6.5 Central Sub-Region

6.5.1 Major Substation Projects

This section summarizes the major required substation projects to support electrification in the Central sub-region resulting from the Future Grid Plan analysis described in Section 6.4. The map below shows the locations of Future Grid Plan substation projects by in service date.

Exhibit 6.9: Locations of the Future Grid Plan (ESMP) Substation Projects in Central Sub-Region by In Service Date



The investments identified in the map above and table below address normal thermal loading constraints projected in the five year and ten-year planning horizons, and establish the capacity needed to support the forecasted load growth. Once implemented, these projects will position the local distribution system to accommodate electrification in a timely manner. The projects will also increase the reliability and resiliency experienced by all customers in the immediate vicinity of the projects, which may include those customers in the community where the substation is located and those in some surrounding communities. Exhibit 6.10 below indicates the first year that an asset addressed by the investment is projected to exceed its normal ratings; this asset may be a substation transformer, distribution feeder, or a combination of multiple assets. For example, the Company is recommending the rebuild of its existing Pratts Junction Substation to increase capacity in the Leominster and Lancaster area. The need date for this investment, tied to the first area overloads experienced, is indicated as 2023. In this year, two feeders are projected to exceed their rated capacity. While operational measures and/or short-term projects could be employed to mitigate these feeder overloads, the Pratts Junction transformers are then expected to exceed their emergency ratings on contingency in 2024. By building out the long-term solution, the Company is ensuring that we do not need to come back to Pratts Junction multiple times over the next decade to increase capacity in a piecemeal and reactive manner, realizing efficiencies. Additionally, by establishing the incremental 76 MW of substation transformer capacity in 2029 through the completion of this project, the Company ensures that the capacity is ready for electrification as it materializes and so customers in this area will experience fewer delays in the ability to adopt electrification technologies.

Investments in the table below reflect distribution (MECO) investments. It is noted that many of the projects have associated transmission investments which, for the Company, will be made by New England Power (NEP). These investments will go through the normal transparent, FERC transmission processes and will be shared via ISO-NE (Independent System Operator New England) process for Transmission Local system Plan (LSP). For the Company, the high voltage side of a substation (i.e., 115kV), substation transformer, transmission tap line, and substation land are all NEP owned. For purposes of completeness, the project names and descriptions below the table include descriptions of the associated NEP components for each location. Specific investment needs may change based on changing conditions over time.

Exhibit 6.10: Central Sub-Region Proposed Investments

Study Area	#	Project	Substation Location - Town	Projected In Service Date	First Year of Overload	Enabled Substation Capacity (MW)[6]
Ayer Clinton	**1**	Laurel Circle Second Transformer	Shirley	2032	2033	66
Gardner Winchendon	**2**	Crystal Lake Feeder Expansion	Gardner	2033	2034	NA
	3	East Winchendon Second Transformer	Winchendon	2029	2028	66
	4	Westminster Second Transformer	Westminster	2029	2028	66
	5	East Westminster Rebuild	Westminster	2029	2028	102

[6] "NA" indicates distribution feeder only project as described at the bottom of Section 6.4

Leominster	**6**	Pratts Junction Rebuild	Sterling	2029	2023	76
	7	Litchfield Street Feeder Expansion	Leominster	2029	2028	NA
Millbury Grafton	**8**	North Grafton Second Transformer	Grafton	2029	2029	66
	9	New Substation Near Grafton	Grafton	2034	2026	132
	10	Pondville Rebuild	Auburn	2034	2035	85
	11	Millbury Feeder Expansion	Millbury	2029	2026	NA
Spencer Rutland	**12**	New Lashaway Feeder Expansion	North Brookfield	2034	2035	NA
	13	Meadow Street Feeder Expansion	Spencer	2030	2031	NA
	14	Treasure Valley Feeder Expansion	Paxton	2031	2032	NA
Webster Southbridge Charlton	**15**	East Webster Feeder Expansion	Webster	2029	2023	NA
	16	North Oxford Second Transformer	Oxford	2029	2030	66
	17	West Charlton Second Transformer	Charlton	2029	2025	66
	18	New Substation Near Southbridge	Southbridge	2034	2023	132
	19	New Substation Near Webster	Webster	2034	2023	132
	20	Charlton EV Highway Charging Station	Charlton	2034	2030	132
Worcester North	**21**	New Substation near Greendale	Worcester	2034	2025	132
	22	Worcester Backyard Conversion Program	Worcester	NA	NA	NA
Worcester South	**23**	Grafton Street Rebuild	Worcester	2034	2025	132
Pepperell Dunstable	**24**	Dunstable Feeder Expansion	Dunstable	2032	2033	NA
	25	Groton Street Rebuild	Pepperell	2033	2034	67

Additional details for each investment identified in Exhibit 6.10 above are provided below.

1. Add 2nd Transformer to Laurel Circle

A new 115 to 13.8 kV transformer will be added to the Company's existing Laurel Circle substation and will be supplied by existing 115 kV transmission lines. One new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the Shirley area.

2. Add Two Feeders to Crystal Lake

An additional two feeders will be added to the Company's existing Crystal Lake substation to support load growth primarily in the Gardner area.

3. Add 2nd Transformer to E Winchendon

A new 115 to 13.8 kV transformer will be added to the Company's existing East Winchendon substation and will be supplied by a new 115 kV transmission line extension. One new 55 MVA transform will be installed with four distribution feeders to support the distribution loads primarily in the Winchendon area.

4. Add 2nd Transformer to Westminster

A new 69 to 13.8 kV transformer will be added to the Company's existing Westminster substation and will be supplied by existing 69 kV transmission lines. One new 55 MVA transform will be installed with four distribution feeders to support the distribution loads primarily in the Gardner and Hubbardston areas.

5. Rebuild East Westminster

Both transformers at the Company's existing East Westminster substation will be upgraded and additional feeder positions added to support load growth primarily in the Westminster and Hubbardston areas.

6. Rebuild Pratts Junction

A new 115 to 13.8 kV substation would be installed next to the existing Pratts Junction substation and would replace the existing 115 to 13.8 kV Pratts Junction substation. The new substation will be supplied by existing 115 kV transmission lines. Two 55 MVA transformers will be installed, with eight distribution feeders to support distribution load primarily in the Leominster and Lancaster areas.

7. Add Two Feeders at Litchfield St

Two additional feeders will be added to the Company's existing Litchfield St substation to support load growth primarily in the Leominster area.

8. Add 2nd Transformer North Grafton

A new 69 to 13.8 kV transformer will be added to the Company's existing North Grafton substation and will be supplied by existing 69 kV transmission lines. One new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the Grafton area.

9. Build New Substation near Grafton

A new 115 to 13.8 kV substation near the Sutton and Grafton border would be supplied by a short extension of existing 115 kV transmission lines. The final plans are dependent on land acquisition efforts that will determine the exact location for the new substation. Two 55 MVA transformers will be installed, with eight distribution feeders to support distribution load primarily to the southeast of the Company's existing Millbury Substation.

10. Rebuild Pondville

The Company's existing Pondville Substation will be upgraded and supplied by existing 69kV transmission lines. The substation will be upgraded to include two 55 MVA transformers, with eight distribution feeders to support distribution load primarily in the Auburn area.

11. Add One Feeder to Millbury

An additional feeder will be added to the Company's existing Millbury substation to support load growth primarily in the Grafton, Millbury, and Sutton areas.

12. Add One Feeder at New Lashaway

An additional feeder will be added to the Company's existing Lashaway substation to support load growth primarily in the Brookfield, North Brookfield, and West Brookfield areas.

13. Add One Feeder at Meadow St

An additional feeder will be added to the Company's existing Meadow St substation to support load growth primarily in the East Brookfield and Spencer areas.

14. Add One Feeder to Treasure Valley (Expand 55W3)

The 55W3 feeder at the Company's existing Treasure Valley substation will be upgraded to support customer loads. The feeder only supports DER and does not have any feeder regulation.

15. Add Two Feeders at East Webster

An additional two feeders will be added to the Company's existing East Webster substation to support load growth primarily in the Webster area.

16. Add 2nd Transformer at North Oxford

A new 115 to 13.2 kV transformer will be added to the Company's existing North Oxford substation and will be supplied by existing 115 kV transmission lines. One new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the Oxford area.

17. Add 2nd Transformer at West Charlton

A new 115 to 13.2 kV transformer will be added to the Company's existing West Charlton substation and will be supplied by existing 115 kV transmission lines. One new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the Charlton and Sturbridge areas.

18. Build New Substation near Southbridge

A new 115 to 13.2 kV substation near the Southbridge and Sturbridge border would be supplied by an extension of existing 115 kV transmission lines. The final plans are dependent on land acquisition efforts that will determine the exact location for the new substation. Two 55 MVA transformers will be installed, with eight distribution feeders to support distribution load primarily to the west of the Company's existing Snow St substation.

19. Build New Substation near Webster

A new 69 to 13.2 kV substation near the Dudley and Webster border would be supplied by extending 69kV transmission lines. The final plans are dependent on land acquisition efforts that will determine the exact location for the new substation. Two 55 MVA transformers will be installed, with eight distribution feeders to support distribution load primarily to the west of the Company's existing East Webster substation.

20. Charlton EV Highway Charging Station

To support highway electrification and meet the anticipated demand associated with EV charging infrastructure at the Charlton eastbound and westbound service plazas on I-90, a new 115 to 34.5 kV substation would be supplied from existing 115 kV transmission. Four underground 34.5 kV supply lines would serve the projected EV charging load, with full redundancy. The final plans are dependent on land acquisition efforts that will determine the exact location for the new substation.

21. New Greendale Substation

A new 115 to 13.8 kV substation in the northern part of Worcester would be supplied by extending 115 kV transmission lines. The final plans are dependent on land acquisition efforts that will determine the exact location for the new substation. Two 55 MVA transformers will be installed, with eight distribution feeders to support distribution load primarily to the south of the Company's existing Greendale substation. This includes supporting the retirement and conversion of existing 4 kV substations in the area.

22. Worcester Backyard Conversion Program

The Company's existing overhead backyard construction in Worcester will be replaced with dual ratio pad mounted min-pads or submersible transformers that will be installed on the road-side, with secondary cables running into the backyard. The dual ratio transformers will allow for future voltage conversion. The proposed solution will support the distribution load growth in the Worcester area and will reduce access issues during maintenance and restoration. The existing backyard construction is unable to support the projected electrification load growth; to increase capacity in these areas will require significant investment that will take place over many years as an enduring program that will encompass the 5- and 10-year plans and beyond.

23. Rebuild Grafton Substation

At the Company's existing Grafton Substation, the substation will be rebuilt and supplied by a new 115 kV transmission line extension. Two 55 MVA transformers will be installed, with eight distribution feeders to support distribution load primarily in the central part of Worcester. The rebuilt substation will also support DER enablement by effectively grounding the 13.8 kV system and converting the existing 4 kV substations in the area.

24. Add 1 Feeder at Dunstable

An additional feeder will be added to the Company's existing Dunstable substation to support load growth primarily in the Dunstable area.

25. Rebuild Groton St

The Company's existing Groton St Substation will be upgraded and supplied by existing 69kV transmission lines. The substation will be upgraded to include two 40 MVA transformers, with six distribution feeders to support distribution load primarily in the Pepperell area.

6.5.2 Non-Wire Alternatives

The Company has developed plans to implement and deliver network capacity by when it is forecasted to be needed across the network. However, there are several instances when the expected project implementation date is after the forecasted "need by date," resulting in a gap period where equipment may overload during peak hours. When this occurs, the Company pursues interim or emergency operational measures to mitigate the risk that a peak demand period could cause significant equipment damage that could result in long duration outages. The Company intends to carefully monitor the load growth at these sites as part of its Annual Planning Review processes and appropriately manage the overload risk, including by evaluating the potential deployment of temporary solutions where needed. These temporary solutions may include load transfers to other substations via distribution ties, spot generation deployment, and NWAs.

The Company will prioritize delivery of "bridge to wires" NWA solutions to help reduce the likelihood and severity of expected overloads before needed network infrastructure projects can feasibly be constructed in areas that have the most significant overloading risk. In the Central sub-region the Company has identified six candidate locations for potential NWA projects, which were selected based on having a 5-year or longer "gap period" between "need-by-date" and expected project completion date. Exhibit 6.11 below identifies NWA projects in the Central sub-region. Numbering follows Exhibit 6.10 above of all proposed Central sub-region investments.

Exhibit 6.11: NWA Projects in Central Sub-Region

#	Project	Substation Location - Town	Projected In Service Date	First Year of Overload
6	Pratts Junction Rebuild	Sterling	2029	2023
9	New Substation Near Grafton	Grafton	2034	2026
15	East Webster Feeder Expansion	Webster	2029	2023
18	New Substation Near Southbridge	Southbridge	2034	2023
19	New Substation Near Webster	Webster	2034	2023
21	New Substation near Greendale	Worcester	2034	2025
23	Grafton Street Rebuild	Worcester	2034	2025

The NWA solutions may contain a combination of demand side measures to deploy, procure and activate customer EE and flexible demand, including procurement of services from front of the meter DERs such as ES facilities. As discussed in Section 6.11, the Company will select specific locations for NWAs from this list based on further analysis of the quantified benefits of the overload avoidance and an assessment of customer propensity to provide flexibility in that area. The Company intends to test a variety of methods to determine how to most effectively use NWAs to deliver reliable load reductions to best address the local needs for that part of the network. The NWA mechanisms specific to each project have not yet determined and will be informed by a more detailed assessment of the customer demographics, load profile and network needs for that area.

As policy, the industry, and the Company's NWA capabilities mature and as the load growth continues to materialize, the Company may reprioritize NWA delivery in different and/or additional locations as needed. The Company also may identify use cases to deploy NWAs to defer or avoid network infrastructure investments in addition to the "bridge to wires" use cases included in the table above.

6.5.3 Alternative Cost Allocation Approaches to Interconnect Solar Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing

6.5.4 Alternative Cost Allocation Approaches to Interconnect Battery Storage Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.5.5 Equity and EJ Outreach

Where the above projects have potential impact on EJCs, the Company is committed to ensuring that each community has a voice as energy infrastructure projects are developed. As projects are scoped, potential impacts on EJ populations will be actively considered. In addition, communities will be engaged early in the process so that the Company is able to discuss with them 1) the role the project plays in the distribution system, 2) the electrification benefits that will be realized by the local area, and 3) any community impacts that may be incurred due to construction or ongoing operations of the project. The Company is committed to understanding the perspectives, concerns, and priorities of each individual community that may be impacted by these projects as every neighborhood will be unique.

As discussed in Section 3, the Company has already begun engagement with EJ stakeholders around the Future Grid Plan. It is anticipated that potential organizations for engagement specific to projects identified would include, but not be limited to, organizations such as:

- Worcester Community Action Council
- Central Massachusetts Regional Planning Commission
- Worcester Roots
- Leominster Community Action Counsel
- Spanish American Center of Leominster
- Regional Environmental Council of Worcester

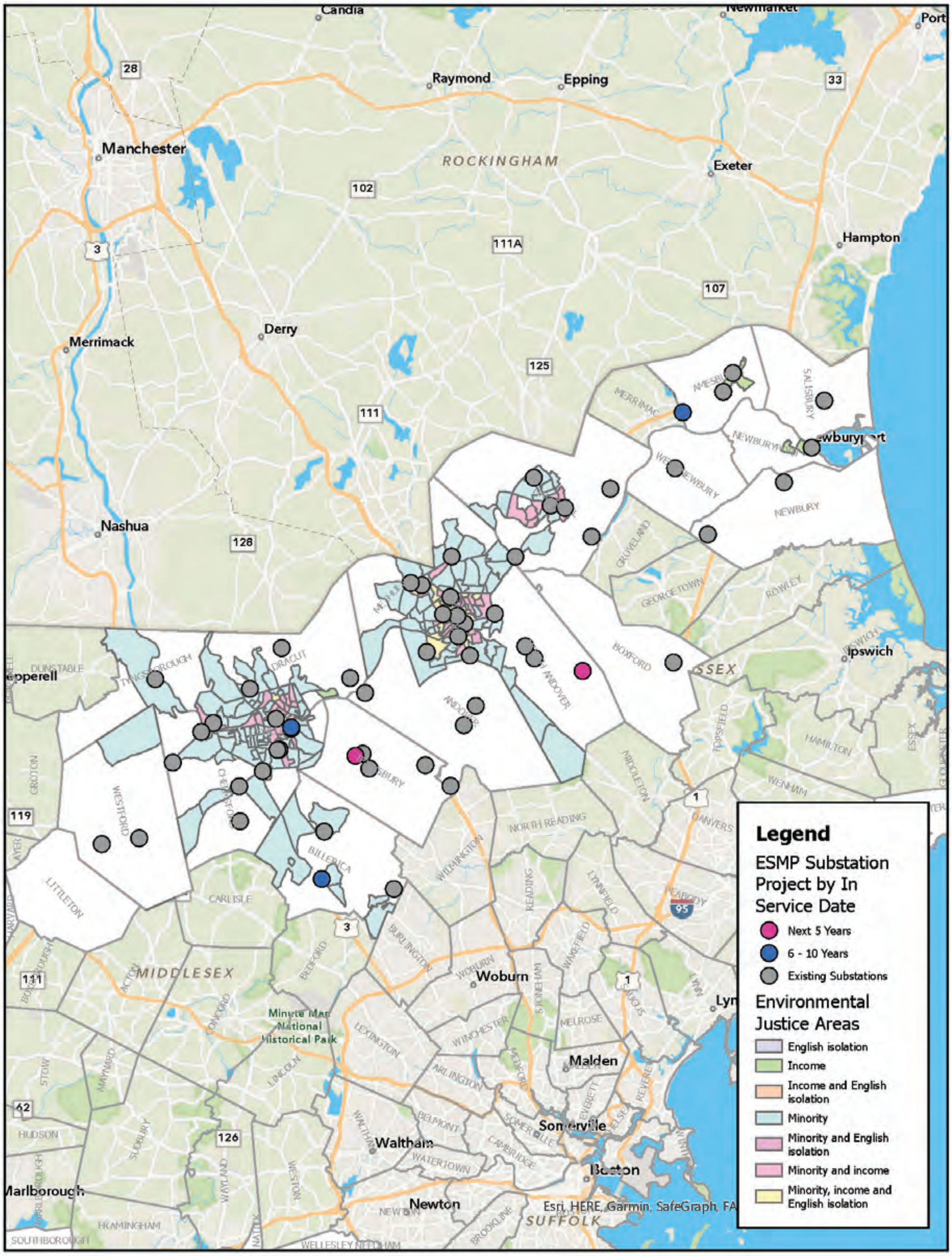
The Company anticipates consulting with these groups early in the process in order to inform broader outreach efforts.

6.6 Merrimack Valley Sub-Region

6.6.1 Major Substation Projects

This section summarizes the major required substation projects to support electrification in the Merrimack Valley sub-region resulting from the Future Grid Plan analysis described in Section 6.4. The map below shows the locations of the Future Grid Plan substation projects by in service date.

Exhibit 6.12: Locations of the Future Grid Plan (ESMP) Substation Projects in Merrimack Valley Sub-Region by In Service Date



The investments identified in the map above and table below address normal thermal loading constraints projected in the five year and ten-year planning horizons, and establish the capacity needed to support the forecasted load growth. Once implemented, these projects will position the local distribution system to accommodate electrification in a timely manner. The projects will also increase the reliability and resiliency experienced by all customers in the immediate vicinity of the projects, which may include those customers in the community where the substation is located and those in some surrounding communities. Exhibit 6.13 below indicates the first year that an asset addressed by the investment is projected to exceed its normal ratings; this asset may be a substation transformer, distribution feeder, or a combination of multiple assets.

Investments in the table below reflect distribution (MECO) investments. It is noted that many of the projects have associated transmission investments which, for the Company, will be made by New England Power (NEP). These investments will go through the normal transparent, FERC transmission processes and will be shared via ISO-NE (Independent System Operator New England) process for Transmission Local system Plan (LSP). For the Company, the high voltage side of a substation (i.e., 115kV), substation transformer, transmission tap line, and substation land are all NEP owned. For purposes of completeness, the project names and descriptions below the table include descriptions of the associated NEP components for each location. Specific investment needs may change based on changing conditions over time.

Exhibit 6.13 Merrimack Valley Sub-Region Proposed Investments

Study Area	#	Project Name	Substation Location - Town	Projected In Service Date	First Year of Overload	Enabled Substation Capacity (MW)
Amesbury/Newburyport	**1**	West Amesbury Second Transformer	Amesbury	2032	2033	66
Billerica	**2**	South Billerica 18 Rebuild	Billerica	2034	2025	103
Lowell	**3**	Perry Street 3 Expansion	Lowell	2034	2023	80
North Andover	**4**	Woodchuck Hill Rebuild	North Andover	2029	2023	83
Tewksbury	**5**	Power Company Road Feeder Expansion	Tewksbury	2029	2025	NA

1. Add 2nd Transformer to West Amesbury

A second 115 to 13.2 kV transformer will be added to the existing West Amesbury substation. This will be a new 55 MVA transformer, with four new distribution feeders to support distribution loads primarily located in the West Amesbury area.

2. South Billerica 18 Rebuild

The existing 23 to 13.2 kV South Billerica 18 substation will be converted to a 115 kV supply to increase its ability to support electrification load growth. An underground extension of area 115 kV transmission will supply the substation, which will consist of two 55 MVA transformers and eight distribution feeders that will primarily supply distribution load in the Billerica area.

3. Perry Street 3 Expansion

The existing Perry 3 substation will be upgraded with two 55 MVA transformers and a second 115 to 13.8kV metal-clad switchgear power station that includes eight feeder positions for 13.8kV distribution load in the Lowell area. An underground extension of the area 115kV transmission will supply the added transformer.

4. Rebuild Woodchuck Hill 56

The existing Woodchuck Hill 56 substation will be upgraded with two 55 MVA transformers and eight distribution feeders that will primarily supply distribution load in the North Andover Area. A new 115kV transmission tap off of the C155N line will be needed to supply the added transformer.

5. Add Two Feeders at Power Co Road 20

An additional two feeders will be added to the Company's existing Power Co Road 20 Substation to support load growth primarily in the Tewksbury area.

6.6.2 Non-Wire Alternatives

The Company has developed plans to implement and deliver network capacity by when it is forecasted to be needed across the network. However, there are several instances when the expected project implementation date is after the forecasted "need by date," resulting in a gap period where equipment may overload during peak hours. When this occurs, the Company pursues interim or emergency operational measures to mitigate the risk that a peak demand period could cause significant equipment damage that could result in long duration outages. The Company intends to carefully monitor the load growth at these sites as part of its Annual Planning Review processes and appropriately manage the overload risk, including by evaluating the potential deployment of temporary solutions where needed. These temporary solutions may include load transfers to other substations via distribution ties, spot generation deployment, and NWAs.

The Company will prioritize delivery of "bridge to wires" NWA solutions to help reduce the likelihood and severity of expected overloads before needed network infrastructure projects can feasibly be constructed in areas that have the most significant overloading risk. In the Merrimack Valley sub-region the Company has identified three candidate locations for potential NWA projects, which were selected based on having a 5-year or longer "gap period" between "need-by-date" and expected project completion date. Exhibit 6.14 below identifies NWA projects in the Merrimack Valley sub-region. Numbering follows Exhibit 6.13 above of all proposed Merrimack Valley sub-region investments.

Exhibit 6.14: NWA Projects in the Merrimack Valley Sub-Region

#	Project	Substation Location - Town	Projected In Service Date	First Year of Overload
2	South Billerica 18 Rebuild	Billerica	2034	2025
3	Perry Street 3 Expansion	Lowell	2034	2023
4	Woodchuck Hill Rebuild	North Andover	2029	2023

The NWA solutions may contain a combination of demand side measures to deploy, procure and activate customer EE and flexible demand, including procurement of services from front of the meter

DERs such as ES facilities. As discussed in Section 6.11, the Company will select specific locations for NWAs from this list based on further analysis of the quantified benefits of the overload avoidance and an assessment of customer propensity to provide flexibility in that area. The Company intends to test a variety of methods to determine how to most effectively use NWAs to deliver reliable load reductions to best address the local needs for that part of the network. The NWA mechanisms specific to each project have not yet determined and will be informed by a more detailed assessment of the customer demographics, load profile, and network needs for that area.

As policy, the industry, and the Company's NWA capabilities mature and as the load growth continues to materialize, the Company may reprioritize NWA delivery in different and/or additional locations as needed. The Company also may identify use cases to deploy NWAs to defer or avoid network infrastructure investments in addition to the "bridge to wires" use cases included in the table above.

6.6.3 Alternative Cost Allocation Approaches to Interconnect Solar Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.6.4 Alternative Cost Allocation Approaches to Interconnect Battery Storage Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.6.5 Equity and EJ outreach

Where the above projects have potential impact on EJCs, the Company is committed to ensuring that each community has a voice as energy infrastructure projects are developed. As projects are scoped, potential impacts on EJ populations will be actively considered. In addition, communities will be engaged early in the process so that the Company is able to discuss with them 1) the role the project plays in the distribution system, 2) the electrification benefits that will be realized by the local area, and 3) any community impacts that may be incurred due to construction or ongoing operations of the project. The Company is committed to understanding the perspectives, concerns, and priorities of each individual community that may be impacted by these projects as every neighborhood will be unique.

As discussed in Section 3, the Company has already begun engagement with EJ stakeholders around the Future Grid Plan. It is anticipated that potential organizations for engagement specific to projects identified would include, but not be limited to, organizations such as:

- Merrimack Valley Planning Commission
- Community Teamwork
- Cambodia Mutual Assistance
- Greater Lawrence Community Action Council
- Middlesex 3 Coalition
- Lowell Chamber of Commerce
- Merrimack Valley Chamber of Commerce

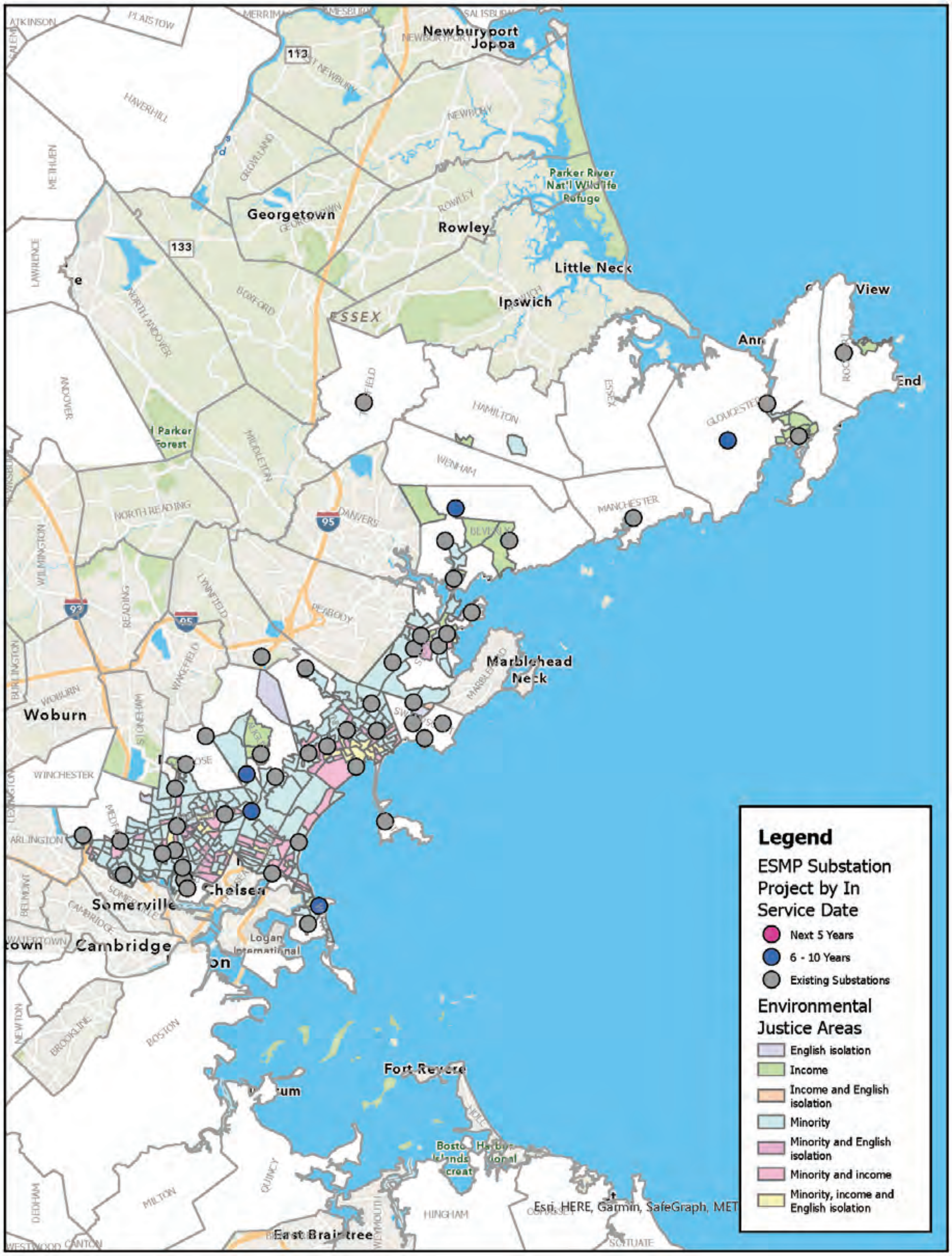
The Company anticipates consulting with these groups early in the process in order to inform broader outreach efforts.

6.7 North Shore sub-region

6.7.1 Major substation projects

This subsection summarizes the major required substation projects needed to support electrification in the North Shore sub-region resulting from the Future Grid Plan analysis described in Section 6.4. The map below shows the locations of Future Grid Plan substation projects by in service date.

Exhibit 6.15: Locations of the Future Grid Plan (ESMP) Substation Projects in North Shore Sub-Region by In Service Date



The investments identified in the map above and table below address normal thermal loading constraints projected in the five-year and ten-year planning horizons, and establish the capacity needed to support the forecasted load growth. Once implemented, these projects will position the local distribution system to accommodate electrification in a timely manner. The projects will also increase the reliability and resiliency experienced by all customers in the immediate vicinity of the projects, which may include those customers in the community where the substation is located and those in some surrounding communities. Exhibit 6.16 below indicates the first year that an asset addressed by the investment is projected to exceed its normal ratings; this asset may be a substation transformer, distribution feeder, or a combination of multiple assets.

Investments in the table below reflect distribution (MECO) investments. It is noted that many of the projects have associated transmission investments which, for the Company, will be made by New England Power (NEP). These investments will go through the normal transparent, FERC transmission processes and will be shared via ISO-NE (Independent System Operator New England) process for Transmission Local system Plan (LSP). For the Company, the high voltage side of a substation (i.e., 115kV), substation transformer, transmission tap line, and substation land are all NEP owned. For purposes of completeness, the project names and descriptions below the table include descriptions of the associated NEP components for each location. Specific investment needs may change based on changing conditions over time.

Exhibit 6.16: North Shore Sub-Region Proposed Investments

Study Area	#	Project Name	Substation Location - Town	Projected In Service Date	First Year of Overload	Enabled Substation Capacity (MW)
Melrose Saugus	1	New Substation Near Malden	Malden	2031	2023	NA
	2	New Substation Near Saugus	Saugus	2034	2028	NA
Revere Winthrop	3	Winthrop 22 Rebuild	Winthrop	2032	2033	132
Cape Ann	4	West Gloucester Feeder Expansion	Gloucester	2032	2033	NA
Beverly	5	North Beverly Rebuild	Beverly	2033	2034	132

1. New Malden Substation

A new 115 to 13.8 kV substation will be built near Squire Road in east Malden, supplied by the nearby area 115 kV transmission. The substation will consist of two 55 MVA transformers and eight distribution feeders that will primarily supply distribution load in the Malden and relieve loading on the existing Maplewood substation.

2. New Saugus Substation

A new 115 to 13.8 kV substation will be built in Saugus, supplied by the existing nearby 115 kV transmission. The substation will consist of two 55 MVA transformers and eight distribution feeders that will primarily supply distribution load in the Saugus and Revere areas.

3. Rebuild Winthrop 22 23/4kV yard to 23/13kV

The existing 4kV yard at Winthrop 22 will be converted to 13kV along with all associated loads and assets to meet the anticipated load growth in the area.

4. West Gloucester Feeder Expansion

An additional 23/13kV modular feeder will be added to the Company's existing West Gloucester 28 substation to support load growth in the area.

5. North Beverly Rebuild

The existing North Beverly 18 substation will be rebuilt from 23/4.16 kV to 23/13 kV with two 20 MVA transformers and six 13.8 kV distribution feeders that will provide additional distribution capacity to meet the forecasted load growth through the conversion of the existing 4.16 kV feeders.

6.7.2 Non-Wire Alternatives

The Company has developed plans to implement and deliver network capacity by when it is forecasted to be needed across the network. However, there are several instances when the expected project implementation date is after the forecasted “need by date,” resulting in a gap period where equipment may overload during peak hours. When this occurs, the Company pursues interim or emergency operational measures to mitigate the risk that a peak demand period could cause significant equipment damage that could result in long duration outages. The Company intends to carefully monitor the load growth at these sites as part of its Annual Planning Review processes and appropriately manage the overload risk, including by evaluating the potential deployment of temporary solutions where needed. These temporary solutions may include load transfers to other substations via distribution ties, spot generation deployment, and NWAs.

The Company will prioritize delivery of “bridge to wires” NWA solutions to help reduce the likelihood and severity of expected overloads before needed network infrastructure projects can feasibly be constructed in areas that have the most significant overloading risk. In the North Shore sub-region the Company has identified two candidate locations for potential NWA projects, which were selected based on having a five-year or longer “gap period” between “need-by-date” and expected project completion date. Exhibit 6.17 below identifies NWA projects in the North Shore sub-region. Numbering follows Exhibit 6.16 above of all proposed North Shore sub-region investments.

Exhibit 6.17: NWA Projects in North Shore Sub-Region

#	Project	Substation Location - Town	Projected In Service Date	First Year of Overload
1	New Substation Near Malden	Malden	2031	2023
2	New Substation Near Saugus	Saugus	2034	2028

The NWA solutions may contain a combination of demand side measures to deploy, procure, and activate customer EE and flexible demand, including procurement of services from front of the meter DERs such as ES facilities. As discussed in Section 6.11, the Company will select specific locations for NWAs from this list based on further analysis of the quantified benefits of the overload avoidance and an assessment of customer propensity to provide flexibility in that area. The Company intends to test a variety of methods to determine how to most effectively use NWAs to deliver reliable load reductions to best address the local needs for that part of the network. The NWA mechanisms specific to each project have not yet been determined and will be informed by a more detailed assessment of the customer demographics, load profile, and network needs for that area.

As policy, the industry, and the Company’s NWA capabilities mature and as the load growth continues to materialize, the Company may reprioritize NWA delivery in different and/or additional locations as needed. The Company also may identify use cases to deploy NWAs to defer or avoid network infrastructure investments in addition to the “bridge to wires” use cases included in the table above.

6.7.3 Alternative cost allocation approaches to interconnect solar projects – exploration of different approaches – pros and cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.7.4 Alternative cost allocation approaches to interconnect battery storage projects – exploration of different approaches – pros and cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.7.5 Equity and EJ outreach

Where the above projects have potential impact on EJCs, the Company is committed to ensuring that each community has a voice as energy infrastructure projects are developed. As projects are scoped, potential impacts on EJ populations will be actively considered. In addition, communities will be engaged early in the process so that the Company is able to discuss with them 1) the role the project plays in the distribution system, 2) the electrification benefits that will be realized by the local area, and 3) any community impacts that may be incurred due to construction or ongoing operations of the project. The Company is committed to understanding the perspectives, concerns, and priorities of each individual community that may be impacted by these projects as every neighborhood will be unique.

As discussed in Section 3, the Company has already begun engagement with EJ stakeholders around the Future Grid Plan. It is anticipated that potential organizations for engagement specific to projects identified would include, but not be limited to, organizations such as:

- Salem Alliance for the Environment
- Essex County Community Foundation
- Community Action Programs Inter-City, Inc.
- Revere Cares
- NAACP Environmental Justice Committee- Mystic Valley Area
- LEO – Learning through Empowering Opportunities, Inc.
- Salvation Army Good Neighbor
- North Shore Community Action Program
- North Shore Chamber of Commerce
- Everett Chamber of Commerce

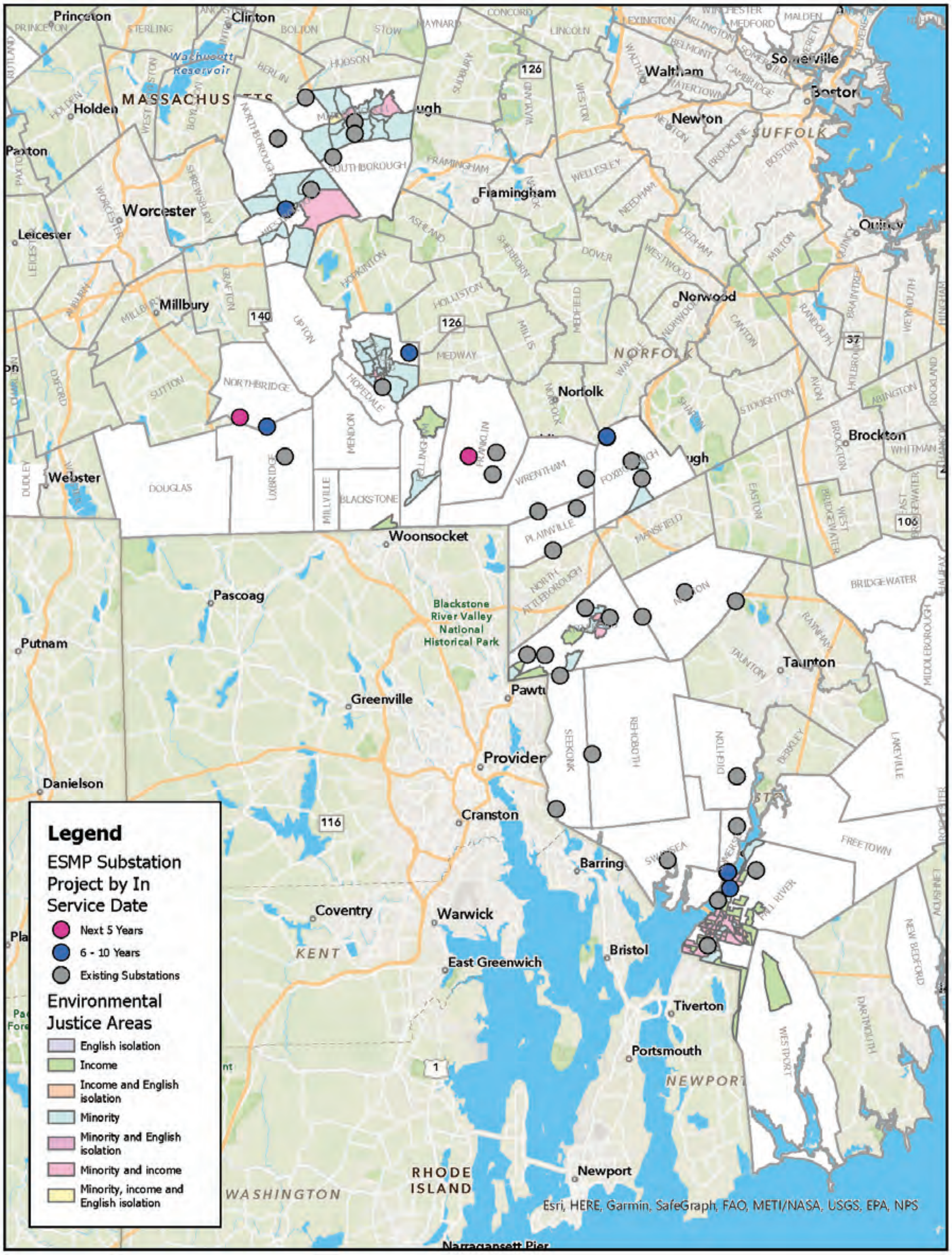
The Company anticipates consulting with these groups early in the process in order to inform broader outreach efforts.

6.8 Southeast sub-region

6.8.1 Major substation projects

This Section summarizes the major required substation projects to support electrification in the Southeast sub-region resulting from the Future Grid Plan analysis described in Section 6.4. The map below shows the locations of Future Grid Plan substation projects by in service date.

Exhibit 6.18: Locations of the Future Grid Plan (ESMP) Substation Projects in Southeast Sub-Region by In Service Date



The investments identified in the map above and table below address normal thermal loading constraints projected in the five-year and ten-year planning horizons, and establish the capacity needed to support the forecasted load growth. Once implemented, these projects will position the local distribution system to accommodate electrification in a timely manner. The projects will also increase the reliability and resiliency experienced by all customers in the immediate vicinity of the projects, which may include those customers in the community where the substation is located and those in some surrounding communities. Exhibit 6.19 below indicates the first year that an asset addressed by the investment is projected to exceed its normal ratings; this asset may be a substation transformer, distribution feeder, or a combination of multiple assets.

Investments in the table below reflect distribution (MECO) investments. It is noted that many of the projects have associated transmission investments which, for the Company, will be made by New England Power (NEP). These investments will go through the normal transparent, FERC transmission processes and will be shared via ISO-NE (Independent System Operator New England) process for Transmission Local system Plan (LSP). For the Company, the high voltage side of a substation (i.e., 115kV), substation transformer, transmission tap line, and substation land are all NEP owned. For purposes of completeness, the project names and descriptions below the table include descriptions of the associated NEP components for each location. Specific investment needs may change based on changing conditions over time.

Exhibit 6.19: Southeast Sub-Region Proposed Investments

Study Area	#	Project Name	Substation Location - Town	Projected In Service Date	First Year of Overload	Enabled Substation Capacity (MW)
Fall River	**1**	New Substation Near Grand Army Highway	Fall River	2034	2026	132
Hopedale East	**2**	Beaver Pond Upgrade	Franklin	2029	2029	37
	3	New Substation in North Foxboro	Foxboro	2034	2023	118.8
Hopedale West	**4**	Rocky Hill Feeder Expansion	Milford	2031	2031	NA
	5	Whitins Pond Feeder Expansion	Northbridge	2029	2027	NA
	6	New Substation Near Northbridge and Uxbridge	Northbridge	2031	2027	132
Marlboro	**7**	Westborough EV Highway Charging Station	Westborough	2034	2030	132
Somerset	**8**	New Substation at Riverside	Swansea	2031	2023	124

1. New Grand Army Highway Substation

A new 115 to 13.8 kV substation near Grand Army Highway in Fall River would be supplied by an underground extension of existing 115 kV transmission lines. The final plans are dependent on land acquisition efforts that will determine the exact location for the new substation. Two 55 MVA transformers will be installed, with eight distribution feeders to support the distribution load center primarily to the northeast of the Company's existing Hathaway Substation.

2. Beaver Pond Substation Upgrade

The two existing 115 to 13.8 kV transformers at Beaver Pond Substation will be upgraded to 55 MVA to support distribution loads primarily in the Franklin and Bellingham areas.

3. New North Foxboro Substation

A new 115 to 13.8 kV substation will be built in northern Foxboro, supplied by an underground line extension of area 115 kV transmission. The substation will consist of two 55 MVA transformers and eight distribution feeders that will primarily supply distribution load in the Foxboro area.

4. Feeder Addition: Rocky Hill

An additional three feeders will be added to the Company's existing Rocky Hill Substation to support load growth primarily in the Milford area.

5. Feeder Addition: Whitins Pond

An additional three feeders will be added to the Company's existing Whitins Pond Substation to support load growth primarily in the Milford area.

6. New Northbridge/Uxbridge Substation

A new 115 to 13.8 kV substation near the Northbridge and Uxbridge border would be supplied by an extension of existing 115 kV transmission lines. The final plans are dependent on land acquisition efforts that will determine the exact location for the new substation. Two 55 MVA transformers will be installed, with eight distribution feeders to support distribution load primarily to the northeast of the Company's existing Whitins Pond Substation.

7. Westborough EV Highway Charging Substation

To support highway electrification and meet the anticipated demand associated with EV charging infrastructure at the Westborough westbound service plaza on I-90, a new 115 to 34.5 kV substation would be supplied from existing 115 kV transmission. Two underground 34.5 kV supply lines would serve the projected EV charging load, with full redundancy. The final plans are dependent on land acquisition efforts that will determine the exact location for the new substation.

8. New Riverside Substation / 4 kV Removal

A new 115 to 13.8 kV substation at the location of the Company's existing Riverside Substation in Somerset will be supplied from existing 115 kV transmission. The new substation will require the retirement of the existing 4.16 kV substation and will consist of two 55 MVA transformers and eight distribution feeders to support distribution load growth in the Somerset and Swansea areas.

6.8.2 Non-Wire Alternatives

The Company has developed plans to implement and deliver network capacity by when it is forecasted to be needed across the network. However, there are several instances when the expected project implementation date is after the forecasted "need by date," resulting in a gap period where equipment may overload during peak hours. When this occurs, the Company pursues interim or emergency operational measures to mitigate the risk that a peak demand period could cause significant equipment damage that could result in long duration outages. The Company intends to carefully monitor the load growth at these sites as part of its Annual Planning Review processes and appropriately manage the overload risk, including by evaluating the potential deployment of temporary solutions where needed. These temporary solutions may include load transfers to other substations via distribution ties, spot generation deployment, and NWAs.

The Company will prioritize delivery of "bridge to wires" NWA solutions to help reduce the likelihood and severity of expected overloads before needed network infrastructure projects can feasibly be constructed in areas that have the most significant overloading risk. In the Southeast sub-region the Company has identified three candidate locations for potential NWA projects, which were selected based on having a 5-year or longer "gap period" between "need-by-date" and expected project completion date. Exhibit 6.20 below identifies NWA projects in the Southeast sub-region. Numbering follows Exhibit 6.19 above of all proposed Southeast sub-region investments.

Exhibit 6.20: NWA Projects in Southeast Sub-Region

#	Project	Substation Location - Town	Projected In Service Date	First Year of Overload
1	New Substation Near Grand Army Highway	Fall River	2034	2026
3	New Substation in North Foxboro	Foxboro	2034	2023
8	New Substation at Riverside	Swansea	2031	2023

The NWA solutions may contain a combination of demand side measures to deploy, procure and activate customer EE and flexible demand, including procurement of services from front of the meter DERs such as ES facilities. As discussed in Section 6.11, the Company would select specific locations for NWAs from this list based on further analysis of the quantified benefits of the overload avoidance and an assessment of customer propensity to provide flexibility in that area. The Company intends to test a variety of methods to determine how to most effectively use NWAs to deliver reliable load reductions to best address the local needs for that part of the network. The NWA mechanisms specific to each project have not yet determined and will be informed by a more detailed assessment of the customer demographics, load profile and network needs for that area.

As policy, the industry, and the Company's NWA capabilities mature and as the load growth continues to materialize, the Company may reprioritize NWA delivery in different and/or additional locations as needed. The Company also may identify use cases to deploy NWAs to defer or avoid network infrastructure investments in addition to the "bridge to wires" use cases included in the table above.

6.8.3 Alternative Cost Allocation Approaches to Interconnect Solar Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.8.4 Alternative Cost Allocation Approaches to Interconnect Battery Storage Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.8.5 Equity and EJ Outreach

Where the above projects have potential impact on EJCs, the Company is committed to ensuring that each community has a voice as energy infrastructure projects are developed. As projects are scoped, potential impacts on EJ populations will be actively considered. In addition, communities will be engaged early in the process so that the Company is able to discuss with them 1) the role the project plays in the distribution system, 2) the electrification benefits that will be realized by the local area, and 3) any community impacts that may be incurred due to construction or ongoing operations of the project. The Company is committed to understanding the perspectives, concerns, and priorities of each individual community that may be impacted by these projects as every neighborhood will be unique.

As discussed in Section 3, the Company has already begun engagement with EJ stakeholders around the Future Grid Plan. It is anticipated that potential organizations for engagement specific to projects identified would include, but not be limited to, organizations such as:

- Groundwork South Coast
- Charles River Watershed Association
- Self Help
- Citizens for Citizens, Inc.
- Westborough CARES
- Source Hub US
- Southern Middlesex Opportunity Council

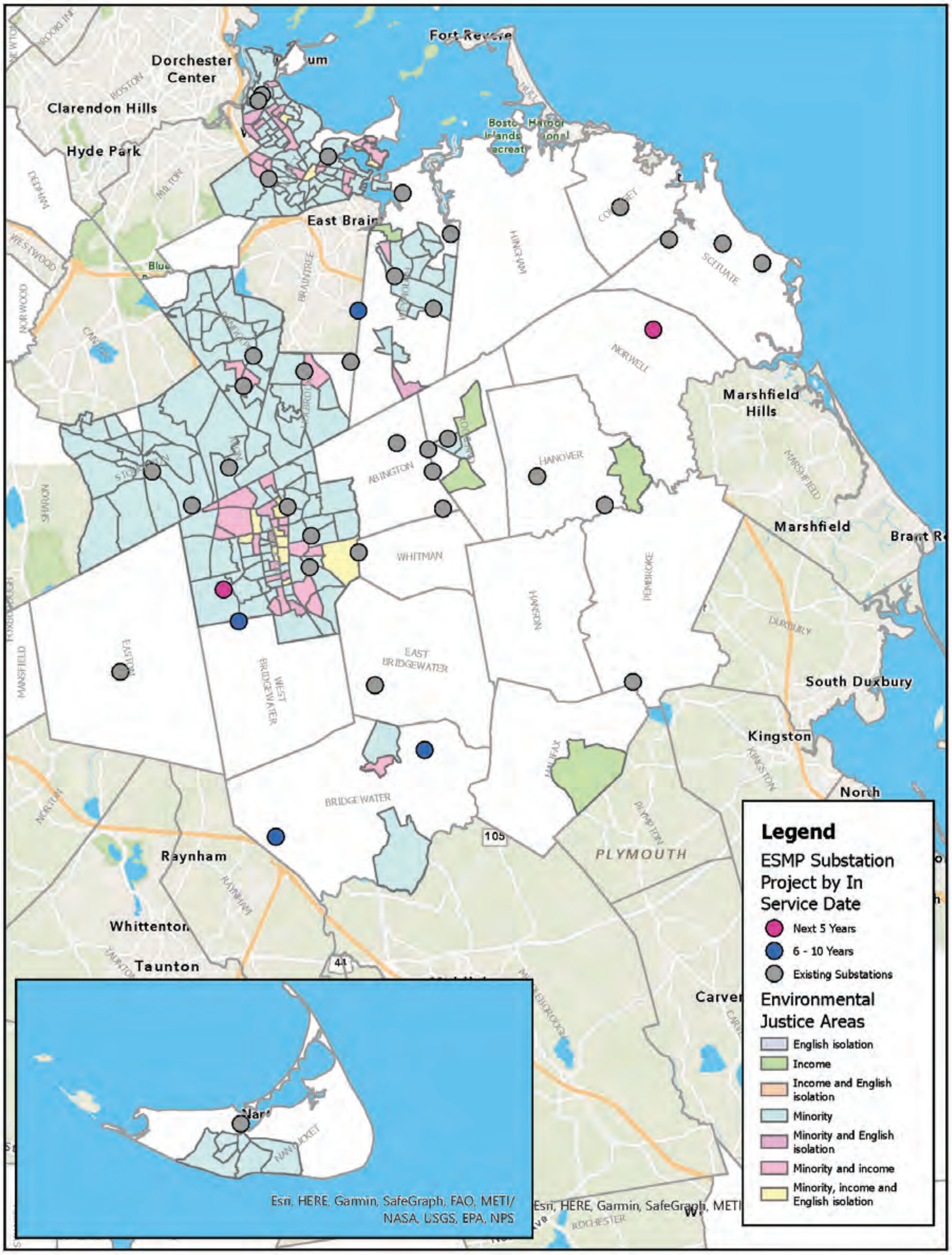
The Company anticipates consulting with these groups early in the process in order to inform broader outreach efforts.

6.9 South Shore sub-region

6.9.1 Major substation projects

This Section summarizes the major required substation projects to support electrification in the South Shore sub-region resulting from the Future Grid Plan analysis described in Section 6.4. The map below shows the locations of the Future Grid Plan substation projects by in service date.

Exhibit 6.21: Locations of the Future Grid Plan (ESMP) Substation Projects in South Shore Sub-Region by In Service Date



The investments identified in the map above and table below address normal thermal loading constraints projected in the five-year and ten-year planning horizons, and establish the capacity needed to support the forecasted load growth. Once implemented, these projects will position the local distribution system to accommodate electrification in a timely manner. The projects will also increase the reliability and resiliency experienced by all customers in the immediate vicinity of the projects, which may include those customers in the community where the substation is located and those in some surrounding communities. Exhibit 6.22 below indicates the first year that an asset addressed by the investment is projected to exceed its normal ratings; this asset may be a substation transformer, distribution feeder, or a combination of multiple assets.

Investments in the table below reflect distribution (MECO) investments. It is noted that many of the projects have associated transmission investments which, for the Company, will be made by New England Power (NEP). These investments will go through the normal transparent, FERC transmission processes and will be shared via ISO-NE (Independent System Operator New England) process for Transmission Local system Plan (LSP). For the Company, the high voltage side of a substation (i.e., 115kV), substation transformer, transmission tap line, and substation land are all NEP owned. For purposes of completeness, the project names and descriptions below the table include descriptions of the associated NEP components for each location. Specific investment needs may change based on changing conditions over time.

Exhibit 6.22: South Shore Sub-Region Proposed Investments

Study Area	#	Project Name	Substation Location - Town	Projected In Service Date	First Year of Overload	Enabled Substation Capacity (MW)
Bridgewater	**1**	Bridgewater EV Highway Charging Station	Bridgewater	2034	2030	132
	2	Mill St Rebuild	Bridgewater	2031	2029	83.5
Brockton	**3**	Belmont Second Transformer	Brockton	2029	2028	16
	4	New Substation Near Brockton and West Bridgewater	Brockton	2034	2028	132
Scituate	**5**	Norwell Upgrade	Norwell	2029	2028	NA
Weymouth	**6**	New Substation Near South Weymouth	Weymouth	2034	2025	132

1. Bridgewater EV Highway Charging Substation

As part of the Electric Sector Modernization Plan (ESMP), DPAM has identified the need to add a greenfield substation. It will be constructed on a Company-owned parcel adjacent to the span between E1 structures 191 and 192 to supply the Northbound and Southbound Service Plazas. The proposed substation will be supplied by a new loop on the 115kV E1 Transmission Line, consisting of an in-line breaker between two double span taps

2. Mill St 912 Rebuild

A new 115 to 13.8 kV substation located at the same parcel that the current Mill Street substation is located. The plans aim to remove the existing equipment at the substation and replace with a new substation with two 55 MVA transformers, with eight distribution feeders to support the distribution load center primarily in the south of the company's existing East Bridgewater Substation.

3. Belmont Substation Expansion

At the Company's existing Belmont Substation, a second 115 to 13.8 kV 55 MVA transformer will be installed, along with four additional distribution feeders. This will fully build out the Belmont substation with 2 55 MVA transformers and eight distribution feeders to support distribution load in the Brockton, Easton, and West Bridgewater areas.

4. New Brockton/West Bridgewater Substation

A new 115 to 13.8 kV substation south of the current Belmont Substation near the West Bridgewater and Brockton border. The substation will be supplied by existing 115 kV transmission lines. Two 55 MVA transformers will be installed with eight distribution feeders to support distribution loads primarily located in the southern portion of the Brockton and Easton areas.

5. Norwell Sub Feeder Expansion

A replacement of the current transformer to a 55 MVA unit and an additional two feeders will be added to the Company's existing Norwell Substation to support load growth primarily in the Norwell and Scituate areas.

6. New South Weymouth 115/13 Substation

A new 115 to 13.8 kV substation south of the current Mid Weymouth substation in southern Weymouth. The substation will be supplied by existing 115 kV transmission lines. Two 55 MVA transformers will be installed with eight distribution feeders to support distribution loads primarily located in the southern Weymouth area.

6.9.2 Non-Wire Alternatives

The Company has developed plans to implement and deliver network capacity by when it is forecasted to be needed across the network. However, there are several instances when the expected project implementation date is after the forecasted "need by date," resulting in a gap period where equipment may overload during peak hours. When this occurs, the Company pursues interim or emergency operational measures to mitigate the risk that a peak demand period could cause significant equipment damage that could result in long duration outages. The Company intends to carefully monitor the load growth at these sites as part of its Annual Planning Review processes and appropriately manage the overload risk, including by evaluating the potential deployment of temporary solutions where needed. These temporary solutions may include load transfers to other substations via distribution ties, spot generation deployment, and NWAs.

The Company will prioritize delivery of "bridge to wires" NWA solutions to help reduce the likelihood and severity of expected overloads before needed network infrastructure projects can feasibly be constructed in areas that have the most significant overloading risk. In the South Shore sub-region the Company has identified two candidate locations for potential NWA projects, which were selected based on having a 5-year or longer "gap period" between "need-by-date" and expected project completion date. Exhibit 6.23 below identifies NWA projects in the South Shore sub-region. Numbering follows Exhibit 6.22 above of all proposed South Shore sub-region investments.

Exhibit 6.23: NWA Projects in South Shore Sub-Region

#	Project	Substation Location - Town	Projected In Service Date	First Year of Overload
4	New Substation Near Brockton and West Bridgewater	Brockton	2034	2028
6	New Substation Near South Weymouth	Weymouth	2034	2025

The NWA solutions may contain a combination of demand side measures to deploy, procure and activate customer EE and flexible demand, including procurement of services from front of the meter DERs such as ES facilities. As discussed in Section 6.11, the Company would select specific locations for NWAs from this list based on further analysis of the quantified benefits of the overload avoidance and an assessment of customer propensity to provide flexibility in that area. The Company intends to test a variety of methods to determine how to most effectively use NWAs to deliver reliable load reductions to best address the local needs for that part of the network. The NWA mechanisms specific to each project have not yet been determined and will be informed by a more detailed assessment of the customer demographics, load profile and network needs for that area.

As policy, the industry, and the Company's NWA capabilities mature and as the load growth continues to materialize, the Company may reprioritize NWA delivery in different and/or additional locations as needed. The Company also may identify use cases to deploy NWAs to defer or avoid network infrastructure investments in addition to the "bridge to wires" use cases included in the table above.

6.9.3 Alternative Cost Allocation Approaches to Interconnect Solar Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.9.4 Alternative Cost Allocation Approaches to Interconnect Battery Storage Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.9.5 Equity and EJ Outreach

Where the above projects have potential impact on EJCs, the Company is committed to ensuring that each community has a voice as energy infrastructure projects are developed. As projects are scoped, potential impacts on EJ populations will be actively considered. In addition, communities will be engaged early in the process so that the Company is able to discuss with them 1) the role the project plays in the distribution system, 2) the electrification benefits that will be realized by the local area, and 3) any community impacts that may be incurred due to construction or ongoing operations of the project. The Company is committed to understanding the perspectives, concerns, and priorities of each individual community that may be impacted by these projects as every neighborhood will be unique.

As discussed in Section 3, the Company has already begun engagement with EJ stakeholders around the Future Grid Plan. It is anticipated that potential organizations for engagement specific to projects identified would include, but not be limited to, organizations such as:

- Southeastern Regional Planning and Economic Development District
- Sustainable Plymouth Coalition for Social Justice
- Nantucket Land Council
- Source Hub US
- Quincy Communication Action Programs
- Action for Boston Community Development, Inc.
- Community Action Programs Inter-City, Inc.
- Self Help, Inc.
- Executive Office of Veterans' Service Main Office
- ROCA
- South Shore Community Action Council

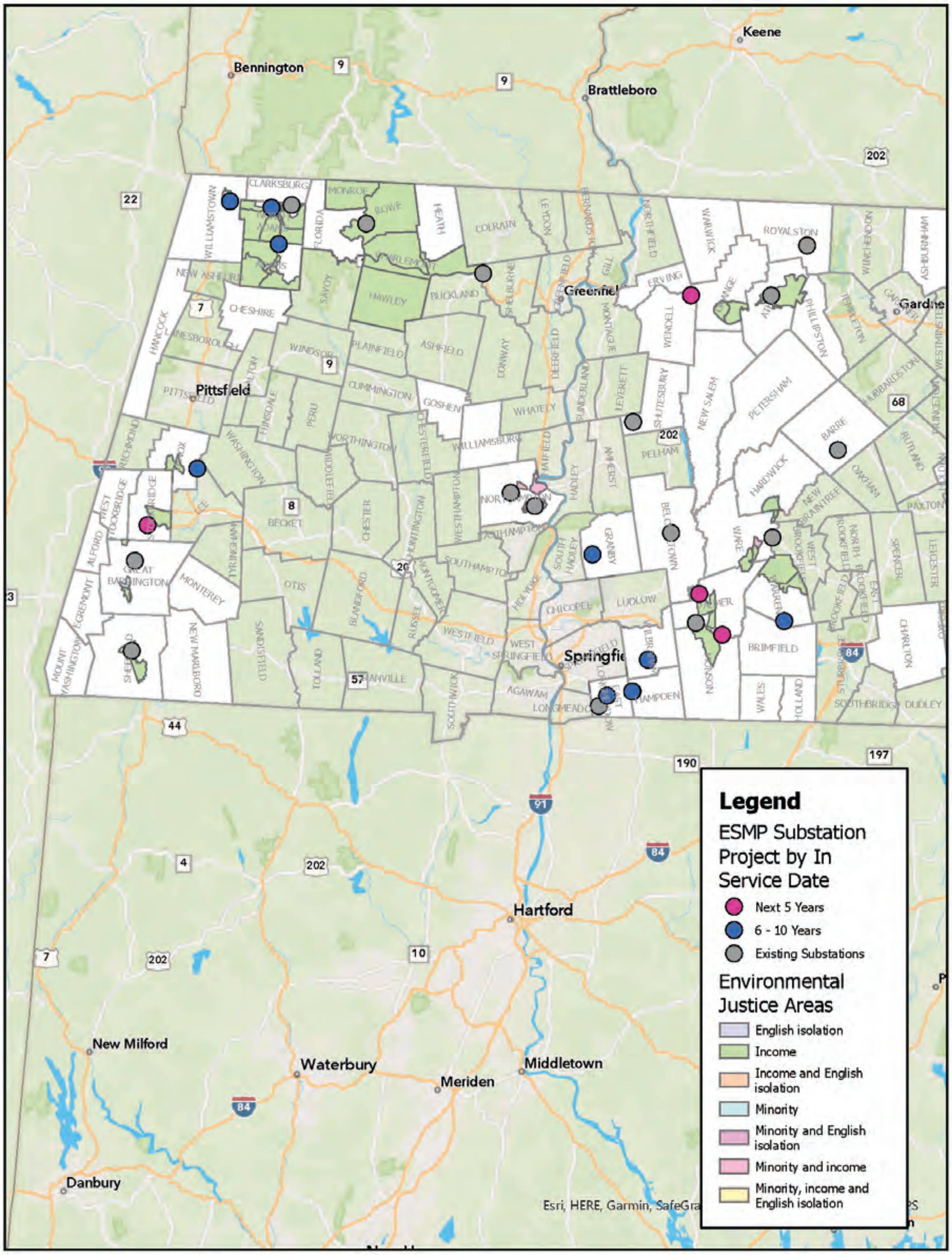
The Company anticipates consulting with these groups early in the process in order to inform broader outreach efforts.

6.10 Western Sub-Region

6.10.1 Major substation projects

This Section summarizes the major required substation projects to support electrification in the Western sub-region resulting from the Future Grid Plan analysis described in Section 6.4. The map below shows the locations of the Future Grid Plan substation projects by in service date.

Exhibit 6.24: Locations of the Future Grid Plan (ESMP) Substation Projects in Western Sub-Region by In Service Date



The investments identified in the map above and table below address normal thermal loading constraints projected in the five-year and ten-year planning horizons, and establish the capacity needed to support the forecasted load growth. Once implemented, these projects will position the local distribution system to accommodate electrification in a timely manner. The projects will also increase the reliability and resiliency experienced by all customers in the immediate vicinity of the projects, which may include those customers in the community where the substation is located and those in some surrounding communities. Exhibit 6.25 below indicates the first year that an asset addressed by the investment is projected to exceed its normal ratings; this asset may be a substation transformer, distribution feeder, or a combination of multiple assets.

Investments in the table below reflect distribution (MECO) investments. It is noted that many of the projects have associated transmission investments which, for the Company, will be made by New England Power (NEP). These investments will go through the normal transparent, FERC transmission processes and will be shared via ISO-NE (Independent System Operator New England) process for Transmission Local system Plan (LSP). For the Company, the high voltage side of a substation (i.e., 115kV), substation transformer, transmission tap line, and substation land are all NEP owned. For purposes of completeness, the project names and descriptions below the table include descriptions of the associated NEP components for each location. Specific investment needs may change based on changing conditions over time.

Exhibit 6.25: Western Sub-Region Proposed Investments

Study Area	#	Project Name	Substation Location - Town	Projected In Service Date	First Year of Overload	Enabled Substation Capacity (MW)
Adams Deerfield	**1**	Brown Street Rebuild	North Adams	2032	2033	36
	2	Adams Feeder Expansion	Adams	2032	2033	NA
	3	Williamstown Rebuild	Williamstown	2032	2033	53
Barre Athol	**4**	Wendell Depot Feeder Expansion	Wendell	2029	2029	NA
Monson Palmer	**5**	Little Rest Road Second Transformer	Warren	2032	2033	66
	6	East Longmeadow Feeder Expansion	East Longmeadow	2033	2034	NA
	7	Five Corners Feeder Expansion	Granby	2033	2034	NA
	8	Palmer Second Transformer	Palmer	2029	2028	62

	9	Thorndike Second Transformer	Palmer	2029	2028	62
	10	West Hampden Second Transformer	Hampden	2032	2033	66
	11	Wilbraham Second Transformer	Wilbraham	2032	2033	66
Northampton Berkshire	**12**	Stockbridge Feeder Expansion	Stockbridge	2029	2028	11
	13	Lenox Depot Rebuild	Lenox	2034	2026	108

1. Rebuild Brown St

The existing Brown St substation will be rebuilt and supplied by two 23 kV supply lines from the Adams substation and two 23 kV supply lines from the rebuilt Walker St substation. The rebuilt substation will consist of two 23/13.8 kV 20 MVA transformers and 4 feeder positions to support distribution load growth primarily in the North Adams and Williamstown area. Additional land around the substation or a new location may be required.

2. Add 1 feeder to Adams 13 kV

An additional feeder will be added to the Company's existing Adams substation to support load growth primarily in the Adams area.

3. Rebuild Williamstown

The existing Williamstown substation will be rebuilt and supplied by three 23 kV supply lines from the Brown St substation. The rebuilt substation will consist of three 23/13.8 kV 20 MVA transformers and 6 feeder positions to support distribution load growth primarily in the Williamstown area. Additional land around the substation or a new location may be required.

4. Add 2 feeders to Wendell Depot

An additional two feeders will be added to the Company's existing Wendell Depot substation to support load growth primarily in the Orange area.

5. Add 2nd Transformer to Little Rest Rd

A new 115 to 13.2 kV transformer will be added to the Company's existing Little Rest Rd substation and will be supplied by existing 115 kV transmission lines. One new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the Brimfield, Holland, Wales, and Warren areas.

6. Add 1 feeder to East Longmeadow

An additional feeder will be added to the Company's existing East Longmeadow substation to support load growth primarily in the East Longmeadow area.

7. Add 1 feeder to Five Corners

An additional feeder will be added to the Company's existing Five Corners substation to support load growth primarily in the Granby area.

8. Add 2nd Transformer to Palmer

A new 115 to 13.2 kV transformer will be added to the Company's existing Palmer substation and will be supplied by existing 115 kV transmission lines. One new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the Palmer and Monson areas.

9. Add 2nd Transformer to Thorndike

A new 115 to 13.2 kV transformer will be added to the Company's existing Thorndike substation and will be supplied by existing 115 kV transmission lines. One new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the Belchertown and Palmer areas.

10. Add 2nd Transformer to West Hampden

A new 115 to 13.2 kV transformer will be added to the Company's existing West Hampden substation and will be supplied by existing 115 kV transmission lines. One new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the East Longmeadow and Hampden areas.

11. Add 2nd Transformer to Wilbraham

A new 69 to 13.2 kV transformer will be added to the Company's existing Wilbraham substation and will be supplied by existing 69 kV transmission lines. One new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the Wilbraham area.

12. Stockbridge Feeder Expansion

At the Company's existing Stockbridge Substation, a second modular feeder will be added. A second 23 to 13.8 kV transformer will be required to supply this new feeder. This project will support distribution load primarily in the Stockbridge area.

13. Rebuild Lenox Depot

At the Company's existing Lenox Depot Substation, the substation will be rebuilt and supplied by a 115 kV transmission line extension from the Woodland Rd substation (Eversource owned). The substation will consist of two 55 MVA transformers and eight distribution feeders to support the distribution loads primarily in the Lenox area. Additional land around the substation or a new location may be required.

6.10.2 Non-Wire Alternatives

The Company has developed plans to implement and deliver network capacity by when it is forecasted to be needed across the network. However, there are several instances when the expected project implementation date is after the forecasted "need by date," resulting in a gap period where equipment may overload during peak hours. When this occurs, the Company pursues interim or emergency operational measures to mitigate the risk that a peak demand period could cause significant equipment damage that could result in long duration outages. The Company intends to carefully monitor the load growth at these sites as part of its Annual Planning Review processes and appropriately manage the overload risk, including by evaluating the potential deployment of temporary solutions where needed. These temporary solutions may include load transfers to other substations via distribution ties, spot generation deployment, and NWAs.

The Company will prioritize delivery of "bridge to wires" NWA solutions to help reduce the likelihood and severity of expected overloads before needed network infrastructure projects can feasibly be constructed in areas that have the most significant overloading risk. In the Western region the Company has identified one candidate location for a potential NWA project, which was selected based on having a 5-year or longer "gap period" between "need-by-date" and expected project completion date. Exhibit 6.26 below identifies NWA projects in the sub-region. Numbering follows Exhibit 6.25 above of all proposed Western sub-region investments.

Exhibit 6.26: NWA Projects in Central Sub-Region

#	Project	Substation Location - Town	Projected In Service Date	First Year of Overload
13	Lenox Depot Rebuild	Lenox	2034	2026

The NWA solutions may contain a combination of demand side measures to deploy, procure, and activate customer EE and flexible demand, including procurement of services from front of the meter DERs such as ES facilities. As discussed in Section 6.11, the Company would select specific locations for NWAs from this list based on further analysis of the quantified benefits of the overload avoidance and an assessment of customer propensity to provide flexibility in that area. The Company intends to test a variety of methods to determine how to most effectively use NWAs to deliver reliable load reductions to best address the local needs for that part of the network. The NWA mechanisms specific to each project have not yet been determined and will be informed by a more detailed assessment of the customer demographics, load profile, and network needs for that area.

As policy, the industry, and the Company's NWA capabilities mature and as the load growth continues to materialize, the Company may reprioritize NWA delivery in different and/or additional locations as needed. The Company also may identify use cases to deploy NWAs to defer or avoid network infrastructure investments in addition to the "bridge to wires" use cases included in the table above.

6.10.3 Alternative Cost Allocation Approaches to Interconnect Solar Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.10.4 Alternative Cost Allocation Approaches to Interconnect Battery Storage Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.10.5 Equity and EJ Outreach

Where the above projects have potential impact on EJCs, the Company is committed to ensuring that each community has a voice as energy infrastructure projects are developed. As projects are scoped, potential impacts on EJ populations will be actively considered. In addition, communities will be engaged early in the process so that the Company is able to discuss with them 1) the role the project plays in the distribution system, 2) the electrification benefits that will be realized by the local area, and 3) any community impacts that may be incurred due to construction or ongoing operations of the project. The Company is committed to understanding the perspectives, concerns, and priorities of each individual community that may be impacted by these projects as every neighborhood will be unique.

As discussed in Section 3, the Company has already begun engagement with EJ stakeholders around the Future Grid Plan. It is anticipated that potential organizations for engagement specific to projects identified would include, but not be limited to, organizations such as:

- Berkshire Regional Planning Commission
- Berkshire Funding Focus
- Berkshire Community Action Council
- NAACP Berkshires Environmental & Climate Justice Committee
- North Quabbin Community Coalition
- Community Action Pioneer Valley
- Markham-Nathan Fund for Social Justice
- Pioneer Valley Workers Center

The Company anticipates consulting with these groups early in the process in order to inform broader outreach efforts.

6.11 New Clean Energy Customer Solutions

To deliver on the Future Grid Plan objectives and continue to create value for customers, the Company's customer program offerings over the five and ten-year investment period will focus on the following:

- Expand upon nation-leading EE, DR, and EV programs.
- Invest in key customer-facing technology that will deliver an improved, modernized experience for customers and help them actively participate in the clean energy transition.
- Accelerate DER interconnection and give customers additional choice for how they interconnect.
- Give customers more control of their bill via new opportunities to earn financial incentives based on shifting and/or reducing energy usage in ways that deliver services to the electric network.

6.11.1 Scale and Expand Existing Programs

As described in Section 6.1, the Company delivers critically important clean energy programs for customers through approved filings, including EE, DR, EHPs (through Mass Save 3-Year Plans) and EVs (through the Massachusetts Phase III Plan). Together, these programs address several of the Future Grid Plan objectives and provide quantifiable and qualitative benefits to customers in delivering the clean energy transition. The Company proposes to continue and extend those programs beyond their currently approved scope in alignment with the timeline of the Future Grid Plan. Note that EE, DR, and EHP incentives will continue to be delivered through the 3-Year Mass Save Plans and not through the Future Grid Plan.

For EVs, beyond 2026 (the current end date for EV Phase III), the Company has forecasted an extension and expansion of these programs based on the forecasted increase in EVs in operation (VIO). Just as EV Phase III was sized to help Massachusetts meet its targets for EV VIO, the Future Grid Plan includes costs to run similar programs that scale up to meet even higher targets for EV VIO in the last half of the decade. In practice, the specific customer offerings will likely need to be adjusted to ensure the Company supports customers with transportation electrification with the programs they need at fair levels of incentives, but with EV Phase III launching in mid-2023, the Company will learn from its current set of offerings, shifting market dynamics, and state policy before proposing new products and services.

The customer program costs are modeled to represent the Company's EV Make-Ready program costs (i.e., the programs that incentivize customers to install EV charging stations). The Company proposes that its EV programs will continue to fully support utility-side infrastructure for participating customers through the ESMP investment period, with most customers participating in the Company's programs to at least receive utility-side support. For customer-side infrastructure and EVSE rebates, the Company assumes much more limited eligibility criteria in future years, as the Company may propose to provide these incentives to customers with specific needs, such as EJCs, municipalities, and areas with a lack of EV charging availability. Exhibit 6.27 below summarizes current and approved clean energy offerings.

Exhibit 6.27: Current and Approved Customer Clean Energy Offerings

Current and Approved Customer Clean Energy Offerings (i.e., core customer clean energy offering)
Energy Efficiency
Incentives to customers to install measures that improve the EE of their homes (residential) or businesses (C&I)
Demand Response, including Battery Storage
Incentives to residential customers for control of their devices (e.g., thermostats, batteries) during peak load events
Incentives to C&I customers to reduce load or increase exports to the grid during peak load events (Targeted Dispatch and Daily Dispatch)
Electric Heat Pumps
Installation incentives for partially or fully displacing a customer's heat system with EHPs (residential & C&I)
Installation incentives for custom C&I projects that are too large or too unique for a prescriptive solution
Electric Vehicles
"Make-ready" rebates / incentives for residential, multi-unit-dwelling, public and workplace, and fleet customers to offset cost of EV charging installations
Off-Peak charging rebate program that provides rebates to residential customers who charge EVs during off-peak hours

These core customer clean energy offerings will benefit greatly from the deployment of technology investments described in Section 6.3.

For example, with AMI, customers will be able to get personalized, disaggregated insights on their energy usage data, creating opportunities for targeted recommendations on EE measures, as well as more seamless, automated DR program participation opportunities. Data visibility will provide significant benefits for EV programs; the Company will have greater insight into EV usage and charging profiles that can impact program design for incentive programs like managed charging. The improvements in data and visibility will unlock additional flexibility in how those programs can connect customers with grid needs – enabling the Company to better build a smarter, stronger, and cleaner grid without having to overbuild it.

DERMS will enable customer DERs to be integrated into the distribution grid in new ways by enabling the Company to dispatch resources more optimally, creating new value streams for customers who are interested in participating in more advanced, dynamic forms of DR.

6.11.2 New proposed clean energy customer solutions

The new technology investments described in Section 6.3 investments will also unlock opportunities for new clean energy customer solutions outlined in greater detail below.

- The 2025-2029 period of the Future Grid Plan will focus on expanding customer clean energy programs by leveraging technology investments (e.g., AMI, DERMS) and improved data capabilities, as well as piloting and testing out new customer solutions with the support of those foundational technologies.
- The 2030-2034 period will focus on leveraging those capabilities to deliver scaled programs with broader participation and impact as customer needs evolve, and once those technologies are fully deployed and mature.

Exhibit 6.28: Proposed Additional Customer Clean Energy Offerings and Alignment with Future Grid Plan (ESMP) Objectives

	Reliability	RE / DER	Storage	Climate Impacts	Electrification	Ratepayer Impact
Scale and evolve clean energy programs for Energy Efficiency, Heat Pumps, and Demand Response (through future separate filing)	✓		✓		✓	✓
Scale and evolve Clean Transportation Programs					✓	
Flexible Connections for EVs – Offer commercial and fleet EV charging customers to connect fleets in advance of system upgrades in constrained areas by allowing NG to actively manage charging					✓	
Targeted Energy Efficiency and Demand Response as Non-Wire Alternatives – Offer additional EE and DR incentives to customers to reduce peak load based on targeted distribution network constraint	✓	✓	✓		✓	✓
Virtual Power Plant as Non-Wires Alternative – Aggregate BTM solar, connected batteries and thermostats to deliver grid services based on targeted distribution network constraint	✓	✓	✓		✓	✓
Leverage Flexibility Market Platform for Non-Wires Alternatives – Run auctions for flexibility service products based on targeted distribution network needs	✓	✓	✓		✓	✓
Resilient Neighborhoods Program – Develop and build solar + storage projects in EJCs to deliver resiliency benefits (through future separate filing)	✓	✓	✓	✓		
Time-Varying Rates – Offer customers AMI-enabled rates that support smart use of the grid and reduce the overall costs of the clean energy transition (through future separate filing)			✓		✓	✓

1. **Flexible Connections for EVs:**

As discussed in other sections, the timelines required to build out infrastructure for large EV fleet charging projects can be substantial, taking two to five years or more in some situations. This is significantly slower than both customer expectations and vehicle procurement timelines, which can often be less than one year. This presents a large challenge to fleet operators to meet the ZEV goals, because the lead times for utility system upgrades prevent them from fully satisfying their demand. Fleet operators of all types could be impacted by these project timelines, including large fleet depots, mixed-use or multiple customer depots, and highway charging sites.

To address the fleet operators' challenge of long lead times for utility system upgrades, the Company can offer commercial and fleet EV charging customers with an alternative EV connection service option in lieu of or as an interim mitigation while waiting for utility system upgrades, eliminating customer frustration over project costs and/or lead times to place their projects in-service as quickly as possible to meet the Commonwealth's goals. This solution is called Flexible Connections for EV and will build from the Company's ARI demonstration project.

The Flexible Connections solution allows fleet operators, under specific conditions, to charge their vehicles prior to the completion of construction of system upgrades by temporarily having the Company actively manage the facility within the capabilities of the existing grid infrastructure. Typical customer connections are limited by the peak demand on existing grid assets, but the Flexible Connections solution can allow fleet operators to utilize the existing distribution lines throughout the year, when significantly more capacity is available. This allows fleet operators to install substantially more charging capacity, while increasing the utilization of existing grid assets. Utilizing the DER management solutions of Flexible Connections can actively manage facilities until long lead-time construction projects are completed, potentially reducing the in-service dates of these MW-scale EV projects by two to four years. This is consistent with the "bridge to wires" NWA concept described in Section 6.4.

Discussion with customers to date has been positive, because this actively managed Flexible Connections solution can allow them to meet their ZEV goals faster, reduce more carbon dioxide (CO_2) and $PM_{2.5}$ emissions, and substantially lower costs. The Flexible Connections solution is also beneficial to the grid by increasing the utilization of existing assets, and to ratepayers by deferring transmission and distribution system upgrade costs.

The first five years of investment will be to build, test, and pilot the technology with customers in select locations, while the second five years will focused on scaling the solution to additional customers across broader geographies as vehicle adoption continues to increase.

2. **NWA Solutions:**

As discussed above, the Company utilizes an established process for considering NWAs as it plans and builds the network. Historically, the Company has not found NWAs to be optimal solutions from a customer cost perspective compared to traditional infrastructure projects.

On a system-wide basis, the Company already has a robust process through which it evaluates the impact of its customer-facing demand-side energy programs, such as EE and DR, on its electric load forecasts that it uses to plan necessary infrastructure upgrades. This has already helped offset investment because the Company already relies upon significant load reductions from those programs. Future TVR, described below, will also help reduce the need for infrastructure investments by providing pricing signals to better align load with renewable generation.

Looking forward, the Company plans to leverage multiple technologies and tools to create flexibility that reduces the need for specific "wires" solutions – with increased data and energy usage visibility from AMI, pricing signals from TVR, EV managed charging, and improved grid management, short-term forecasting, and control via DERMS.

Those capabilities will enable the ability to leverage flexible demand in a more targeted, dynamic, and localized way that will limit the magnitude of the total electric infrastructure buildout and/or improve the Company's ability to continue to keep connecting EVs and EHPs at pace above and beyond the "firm capacity" on the network while it is still being built. The Company will utilize the following demand-side approaches to NWAs – which could be projects that either have a need for peak shaving to either defer/avoid the need for that project or to help improve the deliverability of a project at risk of not being constructed when it is needed.

The Company proposes to test three different NWA approaches, summarized below, to reduce peak demand at a subset of the locations identified in sections 6.5.2 – 6.10.2. The ability of the Company to implement these NWA projects assumes authorization to deploy the DERMS Phase II investment described in Section 6.3. Funding for these NWA demonstrations will be provided via the Grid Services Compensation Fund, as introduced in the Regulatory Framework for NWA discussion in Section 6.4 and described below.

- 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. This fund would be used to provide incentive payments for customers participating in the NWA pilot projects described below. Dispatchable DER, flexible load, and targeted EE with capacity to provide grid services would be eligible for compensation consistent with the recommendations from the Grid Service Study and based on the applicable NWA programs below. 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.

To support these NWA efforts, the Company also proposes to work with the other EDCs to develop and demonstrate a compensation framework for providing locational grid services, including mechanisms to increase the value of DER deployed in EJCs. This investment area includes two components designed to ensure fair and equitable implementation.

- Grid Service Study (Joint EDC Proposal). Engage a third-party consultant to support a study of the value of DER and load flexibility as a locational grid service. Building on a 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 EJCs. The study would also recommend process mechanisms to implement compensation framework based on minimizing implementation cost and increasing value to DER facilities. The EDCs are proposing to conduct the study collaboratively with input from stakeholders.
- Equitable Transactional Energy Study (Joint EDC Study). Building upon learnings from the Grid Service Demonstration, the Company proposes a second study to develop recommendations for a more dynamic locational value compensation framework. The study would take into consideration the implication of dispatching large numbers of smaller facilities in a VPP configuration that have the flexibility to choose their level of participation at any point in time. The study would include a framework for dynamic pricing mechanisms to reflect a higher value of DER in EJCs. The result of the Equitable Transactional Energy Study would inform proposals in the Company's 2030-2034 Future Grid Plan.

a. Targeted EE and DR as a Non-Wires Alternative

The Company plans to evaluate opportunities to offer additional EE and DR incentives to customers to reduce peak load and alleviate capacity constraints in areas identified by System Planning. Because EE and DR programs are run on a system-wide basis through existing Three-Year Plans, the Company proposes to utilize separate, to-be-established, demand-side NWA funding to cover the cost of incremental incentives based on targeted network needs for specific sections of the electric network. The incremental incentives would need to be sufficient to drive participation but remain cost-effective relative to the value of deferral or avoidance of the grid infrastructure need.

The costs of these incentives will be based on the value of addressing the particular grid constraint, as anything more expensive than the estimated value would not be cost-effective. Further analysis will be needed to hone the value estimates, as well as to test the market to determine whether those values enable sufficient customer compensation to drive sufficient volume of participation to address the need. The Company will leverage learnings and best practices where applicable from its New York utility affiliate that has deployed a Targeted EE pilot in Sawyer, New York.

b. VPP as an NWA

As referenced briefly in the Section 6.3 discussion of DERMs, a VPP is a network of DERs like solar PV combined with battery storage, EVs, and DR resources that are aggregated via a central dispatch system that utilities can use to optimize power flows across the grid.

The Company proposes to contract with one or more third-party VPP providers to pilot a solution to one of its potential NWA projects with a targeted distribution grid constraint that can be addressed by an aggregation of customer-sited flexible load and/or ESS assets that reverse their energy flow during peak periods. By supporting the grid during these times, customers can save on electricity costs and potentially earn incentives or credits, while the Company will generate learnings on cost-effectiveness, emissions reductions, and customer experience to potentially scale in the 2030-2034 time period. If possible, the Company will prioritize LMI customers and/or EJCs.

c. Leverage Flexibility Market Platform for NWAs

The Company also proposes to leverage its market platform investment included in its DERMs approvals alongside AMI, ADMS, and DERMS investments to procure load flexibility services in more dynamic ways from flexibility service providers, which could include DER customers and/or aggregators.

In particular, the Company will establish a marketplace for flexible service providers so there is a single registry of flexibility on the network. The Company will test the ability of the marketplace to run local auctions for flexibility services to procure, for instance, “x” MW of flexibility in “y” location. The types of procurements may vary based on the specific grid need in that area. Investment in the technology platform is already approved via Grid Mod as part of the Company’s DERMs development. This pilot would cover the *use case* for the market platform, including incremental costs to:

- Compensate customers and/or flexibility service providers that provide contracted flexibility services to address the identified need.
- Standardize commercial agreements upfront for flexibility services to reduce or eliminate negotiations and speed up securing flexibility for the grid.

Costs associated with payments to flexibility service providers will be determined through future procurements based on specific grid needs. The Company will look to expand upon learnings and best practices from piloting a market platform in New York for its NWA program.

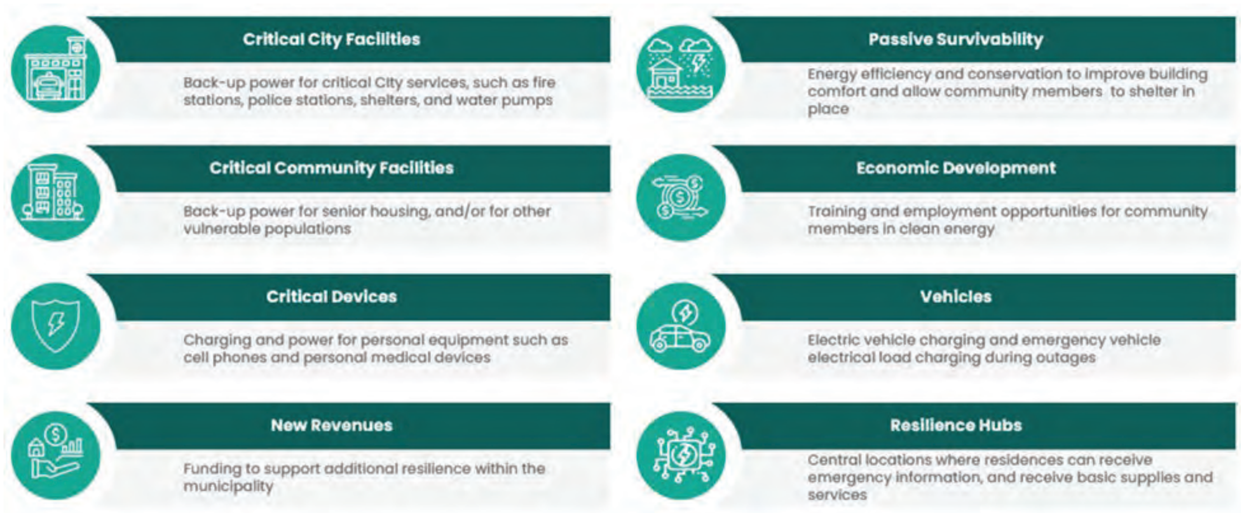
3. Resilient Neighborhoods Program:

Section 77 of MA Bill S.9 - An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy – enables electric and gas distribution companies to construct, own, and operate solar generation facilities paired, where feasible, with ESS facilities. These projects are to be designed to improve community climate adaptation and resiliency for municipalities in their service territories. The Company’s in-development Resilient Neighborhoods Program (RNP) aims to develop such projects to support communities in need, with a strong preference for bringing these benefits to EJCs. The Company is currently evaluating sites and engaging with communities for the first round of project development. Proposals will be filed in a separate filing once detailed projects, costs, and benefits are determined.

As a foundational effort for this program, the Company worked in partnership with the National

Renewable Energy Lab (NREL) to identify different types of Resiliency Benefits that could be offered to municipalities through a locally sited, utility-owned solar project. Exhibit 6.29 below lists eight benefits categories to be considered when engaging with municipalities on how to best provide climate adaptation and resiliency benefits through each utility-owned project.

Exhibit 6.29: Types of Climate Adaptation and Resiliency Benefits to Consider when Engaging Municipalities on Utility-Owned Projects



Source: Converge Strategies

The Resilient Neighborhood Program will help build grid and customer resiliency by providing an increased ability to respond to, withstand, and recover from adverse situations from climate change. It will also result in the integration of new distributed renewable energy projects in the form of solar and storage facilities that will help to achieve state decarbonization goals. Further, the program will prioritize projects in EJCs.

Through the Resilient Neighborhood Program, the Company will work with local municipalities and other stakeholders to explore a menu of resiliency opportunities that may include colocated EV charging. As the transportation sector increasingly electrifies, EV charging may provide another layer of resiliency to these communities. The collocated EV chargers may qualify for the incentives through the Company's EV program which will provide communities agency over the design of the charging to meet local resiliency needs.

4. Time-varying Rates:

New electricity rate designs, enabled by the Company's investment in AMI, are a core component of the Company's strategy for meeting the Commonwealth's energy goals efficiently and affordably. Innovative rates can provide customers with incentives and choices that support smart use of the grid, incentivize electrification, and reduce the overall costs of the energy transition.

The Company intends to formally propose AMI-enabled rates (also referred to as TVR) as part of a separate Department proceeding. This discussion as part of the Future Grid Plan is intended to:

- Highlight the importance of new rates for residential customers in achieving Future Grid Plan goals
- Outline the Company's principles for innovative rate design and implementation

- Provide insight into potential implementation timelines for innovative rate designs

This discussion focuses on residential rates, given that residential customers are the largest customer class and may have the greatest capacity to respond to new rates.

The Company sees rate design as critical in delivering the following benefits—all while preserving cost-reflective rates:

- Aligning customer incentives to shift energy consumption away from peak time, resulting in reduced investment needs and creating the most affordable grid possible
- Incentivizing and enabling electrification by making electrified technologies more affordable to operate

The Company's Principles for AMI-Enabled Rate Design and Implementation:

The Company is actively working to develop and study rate designs that will be most effective for customers and the Commonwealth. This section outlines the Company's current principles for developing and implementing these rates. This section discusses rates for both the energy supply (i.e., the cost of generation) and energy delivery (i.e., the costs of transmission and distribution service).

- Basic service rates for energy supply should include a time-varying component
- Rate design should reduce inefficient disincentives to electrification that are inherent in legacy volumetric delivery rates
- Rollout of new rate designs should be structured to reach as many customers as possible—not just early adopters
- Price signals in rates should be strong enough to drive behavior change
- The mass-market transition to AMI rates should be phased and/or coupled with bill protections for customers
- Customers should receive clear communication and assistance in choosing and adapting to AMI rates, particularly LMI/disadvantaged customers

Timeline for Implementation:

The Company is committed to implementing new rate designs and accruing their benefits for Massachusetts customers as quickly as practical. The Company is also committed to ensuring that the rollout proceeds equitably, provides a positive customer experience, and creates a smooth transition for the most customers possible onto new rate designs. Balancing these objectives indicates the need for a phased approach to the rollout of new rates, to proceed as enabled by the phased AMI implementation that is already underway.

The Company's multi-year AMI implementation plan aims to roll out AMI infrastructure to 30% of Massachusetts customers by the end of 2025, 70% by the end of 2026, and 100% by the end of 2027. As metering and network infrastructure becomes available, The Company intends to propose a three-phase approach to implementing new rate designs.[7]

- **Phase I: Pilots (2026-2027)**

Conducting pilots of new rate designs prior to large-scale rollout would provide the Company with preparation and insight to support an effective large-scale implementation. By the end of 2025, several hundred thousand customers will have AMI infrastructure installed. The Company intends to develop

[7] Note: This timeline is preliminary and subject to change based on factors including changes in the Company's AMI deployment schedule.

proposals for one or more pilots involving a subset of these customers, and to present them in the appropriate regulatory venue. Ideally customers participating in pilots would begin new rates at least 12-18 months after AMI installation; this provides a baseline of energy use data that gives customers an understanding of potential savings areas, and also provides the Company with a basis against which to measure the impacts of rate design. The Company gained significant insights from its 2014-2016 time-of-use rate pilots in Worcester and aims to build on the insight and experience from these pilots.

These pilots would provide a testing ground for new rate designs—including new delivery rate designs such as demand rates that have not yet been piloted in a Massachusetts context. They would also provide the opportunity to test and perfect IT systems, billing, customer communication, customer energy insights, and other elements that will inform a full-scale AMI rollout.

- **Phase II: Opt-in Rates for Interested Customers (2028)**

Following the full rollout of AMI meters to all customers by the end of 2027, the Company would make early-access AMI-enabled delivery rates available to interested customers on an opt-in basis. Waiting until all customers have access to AMI meters before offering an opt-in rate ensures fairness and provides the opportunity for a smooth implementation that is fully informed by learning curves and experience from the Phase I pilots. These rates would be available to all interested customers but would be offered prior to a full-scale transition and communications campaign aimed at all customers. The early-access rates would provide the opportunity for households to begin generating customer and grid benefits from TVR and would likely offer sharper price signals than an initial mass-market rate.

Section 7

5-year Electric Sector Modernization Plan

This section summarizes the overall costs and benefits of the Future Grid Plan and explains the challenges and risks to delivering against the Plan.

Key Take-Aways

- The Future Grid Plan's incremental investments to meet the Commonwealth's clean energy and climate goals depend on the foundation of the Company's core capital investment plan, in-flight investments already approved by the Department (such as Grid Modernization and AMI) and pending proposed CIPs.
- The Future Grid Plan demonstrates the need for approximately $2 billion of incremental investment over 2025-2029 to meet customer needs and build a network that supports the Commonwealth's net zero transition.
- The Company's robust Plan development included extensive engineering options evaluation, platform technology roadmaps, extension of Department approved Grid Modernization technology deployment, and customer insight-driven program development.
- External review by leading experts from The Brattle Group and 1898 & Co. corroborate the robustness of the Company's Plan and its alignment with Commonwealth goals.
- The Future Grid Plan delivers significant benefits to customers and communities across a range of areas, including reliability, GHG emission reductions, and customer choice and control over energy usage.
- To make the needed incremental investments to achieve the Commonwealth's net zero goals, the Company must be able to fund the investment efficiently without the risk of regulatory lag for making the right investments.
- The scale of the investment will require The Company to work differently. We are actively working to identify and address the key risks to delivery of the Plan, including supply chain and workforce challenges.

7.0 5-year Electric Sector Modernization Plan

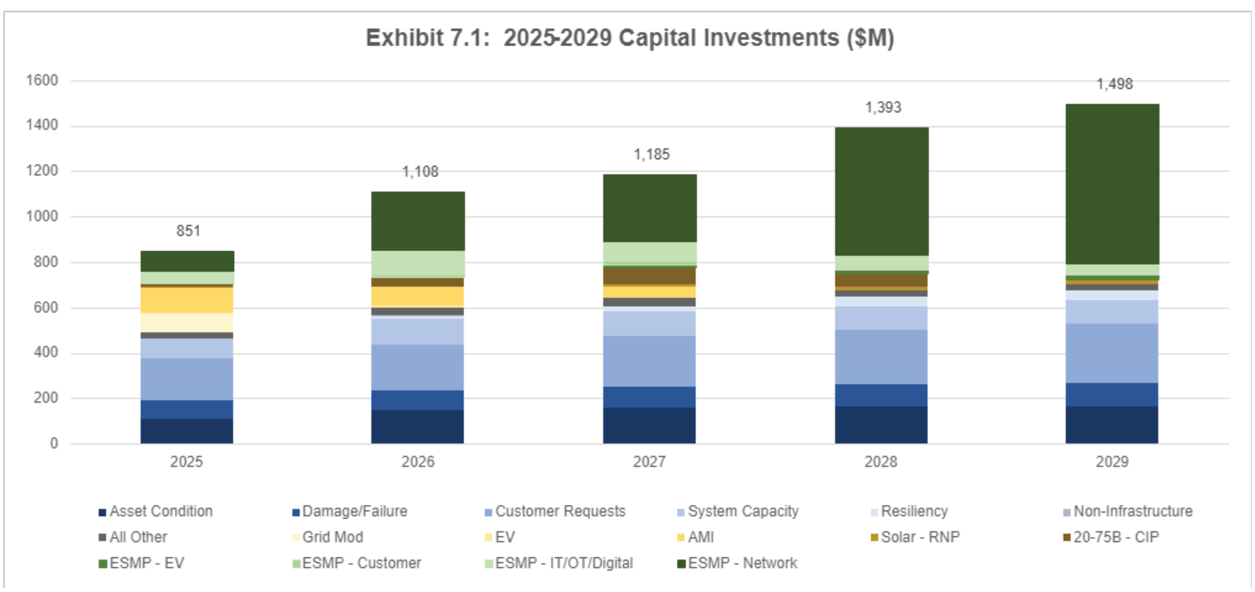
As part of its distribution rate case that will be filed in the fall of 2023, the Company will propose a cost recovery mechanism that enables us to make the level of investment for the first 5 years of this plan. If approved by the Department, this cost recovery mechanism will permit the Company to make the needed core and incremental investments as described herein to meet customers' evolving needs and achieve the Commonwealth's net zero goals. This proposed cost recovery mechanism is similar to what is already in place for the Company's incremental Grid Mod investments and will permit the timely recovery of any O&M and in-service capital investment up to a cap, subject to a prudency review in the year following the spend.

7.1 Investment Summary 5-year chart – Base reliability, existing programs (e.g., CIP, EV, EE, GridMod, AMI), and new proposals. Impact on GHG emission reductions

The five-year investment summary below provides a comprehensive view of all active, pending, and proposed investments in alignment with overall public policy goals and customer needs. The five-year investment plan described below uses the best available information on rate case investments that are still under development, assumes continuation of EE programs, the progression of pending capital investment plans (CIPs), and future implementation of the Resilient Neighborhoods program. Of this total five-year investment, the Company's proposed Future Grid Plan investments account for more than $2 billion.

This Future Grid Plan contemplates the approval of investments by the Department at a level that would support the Commonwealth's clean energy and climate goals and meet customers' evolving needs. If necessary, the Company would revisit the investment plan to align with Department decisions on the Future Grid Plan and the Company's forthcoming distribution rate case.

Exhibit 7.1: 2025-2029 Capital Investments ($M)



2025-2029 Capital Investments ($M)

Categories	2025	2026	2027	2028	2029
Base	493	600	642	674	701
Active Programs	217	133	136	76	21
Future Grid - Network	89	252	294	560	701
Future Grid – IT/OT/Digital	49	108	86	64	50
Future Grid – Customer	4	15	15	2	1
Future Grid - EV	0	0	13	17	24
Future Grid Subtotal	**142**	**375**	**408**	**643**	**776**

The overall capital investments plan for 2025-2029 comprises three categories described in more detail below:

1. Base Spending – Electric Operations
2. Active Regulatory Investments
3. Future Grid Plan (ESMP)

Base Spending (blue shade) – Electric Operations – Investments included in the Company's baseline long-range plan aimed at ensuring safe and reliable service to customers.

The Company builds its baseline capital plan based on six investment drivers: (1) Customer Requests/Public Requirements; (2) Damage/Failure; (3) System Capacity and Performance; (4) Asset Condition; (5) Non-infrastructure; and (6) Resiliency.

- **Customer Requests/Public Requirements** projects are required to respond to or comply with Customer Requests/Public Requirements mandates. This work includes CAPEX required to ensure the contractual obligations of the Company adhere to customer and public requirements. These items include new business residential, new business commercial, outdoor lighting, third party attachments, land rights, and public requirements including municipal and customer interconnections.
- **Damage/Failure** category projects are CAPEX required to replace failed or damaged equipment and to restore the electric system to its original configuration and capability following equipment damage or failure. Damage may be caused by storms, vehicle accidents, vandalism or unplanned/other deterioration, among other causes.
- **System Capacity and Performance** projects are required to ensure that the electric network has sufficient capacity to meet the growing and/or shifting demands of customers. Projects in this category are intended to reduce degradation of equipment service lives due to thermal stress and to provide appropriate degrees of system configuration flexibility to limit adverse reliability impacts of large contingencies. In addition to accommodating load growth, the expenditures in this category are used to install new equipment such as capacitor banks to maintain the requisite power quality required by customers and reclosers that limit the customer impact associated with a service event. This category also includes spending to improve the performance of the network such as the reconfiguration of feeders and the installation of feeder ties.
- **Asset Condition** expenditures are those investments required to reduce the likelihood or consequences of failures of transmission and distribution assets. The Company has adopted an asset management approach that relies on a holistic, longer-view assessment of assets and asset systems to inform capital-investment decisions.
- **Non- Infrastructure** represents the portion of the Company's investment budget in systems, tools, and general plant that are required to operate the network. The "non-infrastructure"

category of investment is for CAPEX that does not fit into one of the foregoing categories, but which is necessary to run the electric system. Examples of work in this category might include spending field equipment, large tools, security, test equipment, etc.

- **Resiliency** - Incremental capital investments in hardening distribution system infrastructure to address impacts of climate change as identified by recent climate impact analysis.

Active regulatory investments (yellow shade) – Capital investments included in the Company's long-range plan funded in existing rates through dedicated mechanisms.

- **AMI** - Authorized investments in Department Docket No. 21-81 for new metering infrastructure, communications infrastructure and enabling IT systems, including customer engagement and program management through 2028.
- **EV** - Authorized investments in Department Docket No. 21-91 to build out make-ready infrastructure to support EV charging stations.
- **CIP** – Department Docket No. 20-75-B investments proposed or pending approval to build out infrastructure required to support DER interconnection.
- **Grid Modernization** – Department Docket No. 21-81 authorized investments for 2025 in field devices and OT to support the Commonwealth's established grid modernization objectives.

Future Grid Plan (ESMP) (green shade)[1] – Investments included in this category are intended to further the Commonwealth's clean energy objectives and are incremental to the Base Spending and Active Regulatory Investments. Please refer to Section 6 for more detailed descriptions of these proposed investments and programs, as well as their justification.

- **Network Investments** – Investments identified to proactively meet forecasted loads and capacity needs. This includes Grid Modernization Programs to extend grid-facing investments (See Section 6.3.2 for further description of proposed investments.)
- **Platform Investments** – Investments identified to leverage data, digitalization, and other platforms to optimize infrastructure and meet evolving customer needs.[2]
- **EV Investments** – Investments to continue our EV program to meet the forecasted customer adoption and customer charging needs to accelerate the enablement of clean energy goals.
- **Customer Investments** – Investments identified to enhance the customer experience and to accelerate the enablement of clean energy goals.

In addition to the capital investments described above, the Company must spend in future years to operate and maintain the system and deliver clean energy programs for customers. Proposed Future Grid Plan operating expense represents approximately 8% of the total projected five-year operating expenditures.

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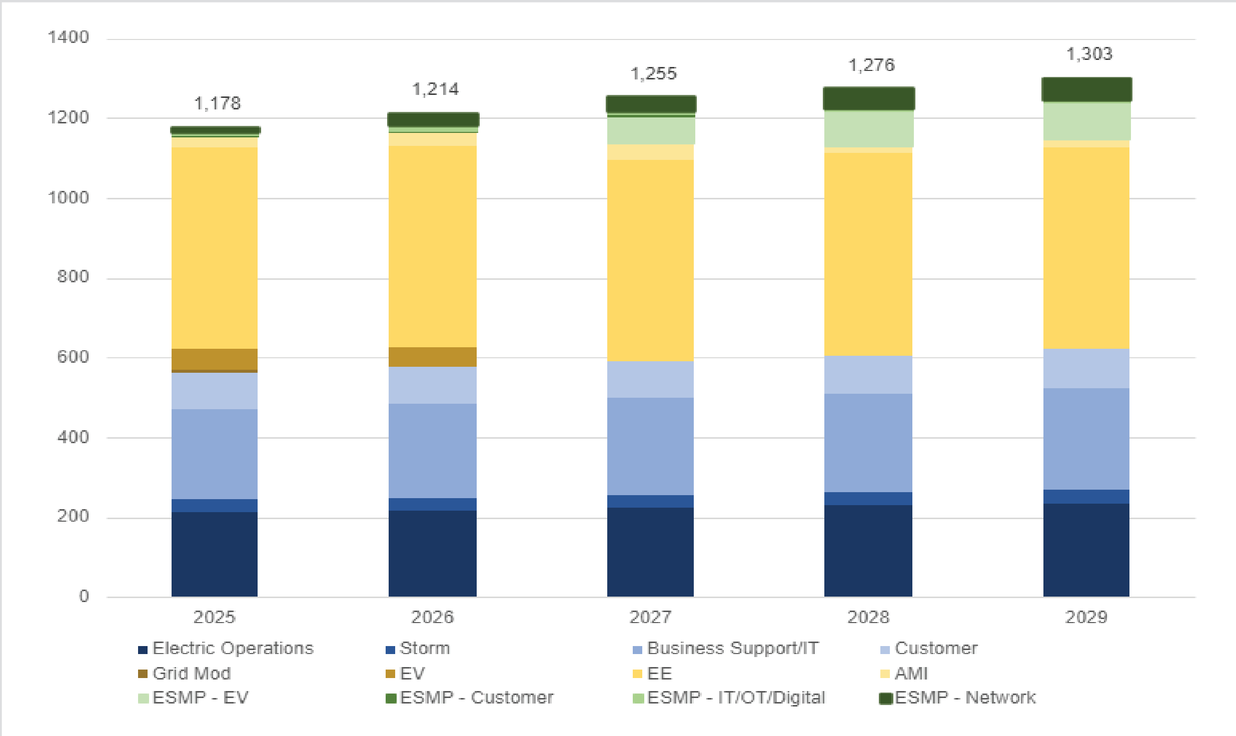
[1] Extensions of the Company's grid-facing and customer-facing investments, including grid modernization and AMI investments, are included in the five-year investment plan in compliance with the Department's Grid Modernization Phase II Order (Order on New Technologies and Advanced Metering Infrastructure), DPU 21-81-B, page 336. Extensions of EV investments are included in the five-year investment plan in compliance with the Department's Phase III Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal order, DPU 21-91, page 158.

[2] Note that many of the platform and some customer investments may be delivered through National Grid's service company entity and subject to suitable cost allocations to the Company. The Future Grid Plan has represented the initial allocated investment in the CAPEX views. Costs incurred through the service company are allocated to benefitting entities and charged to said entities through rental charges.

Exhibit 7.2: 2025-2029 Operating Expense ($M)



2025-2029 Operating Expenditures ($M)

Categories	2025	2026	2027	2028	2029
Base	561	576	591	606	622
Active Programs	597	591	550	526	527
Future Grid - Network	11	30	33	48	56
Future Grid – IT/OT/Digital	6	14	10	8	6
Future Grid – Customer	3	4	4	2	1
Future Grid - EV	0	0	67	87	91
Future Grid Subtotal	**20**	**48**	**114**	**144**	**154**

Operating expenses are classified into the following three categories:

- **Run the Business** (blue shade) - Spending included in the Company's budget for equipment maintenance and repair, major storm response, business support (e.g., human resources, accounting), customer support and call center, and information technology. See Electric Operations, Storm, Business Support/IT, and Customer costs above.
- **Clean Energy Programs** (yellow shade) - Spending on customer programs to support EE, DR, EH, and EV charging and deployment of AMI.[3]

[3] Note that spending on energy efficiency, DR, and heat electrification is approved through the Company's three-year energy efficiency plan. The 2025-2027 plan has not yet been submitted, but the Company provides the portfolio spending from the final year of the current three-year plan https://ma-eeac.org/wp-content/uploads/Exhibit-1-Three-Year-Plan-2022-2024-11-1-21-w-App-1.pdfand shown in Exhibit 7.2 as an estimate for completeness. For more details on the three-year plan, see: https://ma-eeac.org/wp-content/uploads/Exhibit-1-Three-Year-Plan-2022-2024-11-1-21-w-App-1.pdf.

- **Future Grid Plan** (ESMP) (green shade) - The Company proposes incremental operating expenses for the programs described in Section 6.3.2. Additional funding in this category provides for additional resources required for system forecasting and planning, delivering the larger portfolio, and control center and system operations engineering support functions.

The investments described in the first five years of this Future Grid Plan are necessary to make progress towards the Commonwealth's goals for GHG emission reductions and net zero by 2050. The Company recognizes that it plays a role both in reducing its own direct GHG emissions and delivering an electric network that can enable and effectuate reduction in the main contributors to GHG emissions today: transportation, energy production, and heating. The Company's DR and EE programs will continue to play key roles in both driving and delivering GHG reductions, but the Company must now ensure it has a network with the appropriate capacity and reliability to enable and provide necessary supply for the broader efforts around the electrification of transportation and heating, as well as the connection of more DERs. The investments the Company describes in this section are enablers for GHG reductions, building the capacity that will support the broader policy objectives and customer adoption needs proactively. The investment plan will allow for a seamless energy transition and the broader decarbonization of transportation, heat, and energy production.

7.1.1 Alternatives to Proposed Investments – Estimates of Impact of Investment Plan Alternatives

The Company undertook a comprehensive assessment of the overall network needs considering the system's current state and the needs for future electrification and customer benefit realization. When considering alternatives, the Company prioritized safety and reliability, supporting projected load and capacity needs, and preparing the network for forecasted growth.

The reality is that the Company needs to act now to deliver the broader capabilities and network capacity needed for the energy transition. Delay or deferral of these foundational investments risk not having the network capacity and supporting technology needed to achieve the Commonwealth's GHG reduction goals.

The Company's Future Grid Plan is the result of a robust process that builds on years of work developing investment plans, technology roadmaps, and customer strategies to address customer needs and clean energy goals. The following subsections describe the process undertaken to evaluate major categories of investment alternatives. In addition, for development of the Future Grid Plan, the Company engaged outside experts (The Brattle Group and 1898 & Co.) to review and opine on the Plan in terms of whether the proposed portfolio of solutions is aligned with industry best practices and the engineered alternatives and technology recommendations are reasonable. Their reports are provided in the Appendix.

Network Investments

The Company follows a rigorous Network Development Process to anticipate and plan for network infrastructure projects and then methodically develop and deliver them. The first two stages of this robust Network Development Process were carried out in preparation for this Future Grid Plan: (1) needs case development and (2) option selection.

Driven by the Distribution Engineering Planning Standard, needs cases for each project were developed based on system or customer-driven requirements. Scopes of work were developed based on asset condition assessments, system modeling, and opportunities were identified to bundle scope with other required work or existing projects at the given site.

These high-level options were then reviewed and analyzed, comparing these options for scope, cost, constructability, schedule, and risk to complete the project by the needed date. Permitting, work dependencies, bundling opportunities, parallel projects, and other considerations were also evaluated at this stage. This process was carried out by a dedicated multi-disciplinary team of experienced engineers, operations experts, cost estimators, and other experts to determine the preferred option to address each need. The Company has identified priority opportunities to explore NWAs (see sections 6.5.2 – 6.10.2).

The alternative path of not acting upon these investments would create consequences, such as having insufficient network capacity to serve load growth, and as a result having insufficient capacity to serve new DER, EV charging and EHP needs, which in turn would negatively impact the achievement of the Commonwealth's climate goals.

Grid Modernization Investments

This category of investments is a direct extension of the Grid Modernization Plan (GMP), which underwent rigorous Department review; these investments were ultimately approved. These investments were developed prudently to maximize customer benefit and network performance, complementing the network infrastructure buildout. The following are the Department's Grid Modernization objectives:

- Optimize system performance (by attaining optimal levels of grid visibility, command and control, and self-healing);
- Optimize system demand (by facilitating consumer price-responsiveness); and
- Interconnect and integrate DERs.

Projects that embodied these criteria were selected to be included in the GMP and this Future Grid Plan.

Other Platform Investments

The Company identified the capabilities that would be needed to meet customer expectations and Commonwealth clean energy and climate goals and determined what data would be needed. From there, the Company looked at how platforms could be built to extract, digitize, centralize, manage, optimize and then scale those data assets. This insight and the assessment of the Company's own existing internal data platforms demonstrated the need for drastic improvement to continue to maintain the pace of growth of network infrastructure, while supporting electrification and meeting evolving customer needs.

The Company completed extensive road mapping exercises to determine which initiatives would need to be foundational, enabling, or transformational. These roadmaps found that all underlying data must be real-time, accurate, interoperable, and thus scalable for transformational capabilities.

Customer Proposals

The Company's new customer offerings proposals come from insights from experience with current offerings, customer market intelligence, industry best practices, and gaps in meeting customer needs and enabling the net zero transition. The following are some factors that the Company considers in developing and evaluating new customer clean energy offerings, including for the Future Grid Plan:

1. Enablement of acceleration of the path to net zero;
2. Present and future customer needs;
3. Customer affordability;
4. Benefits to EJCs and low-income customers;
5. Scalability and speed-to-market;
6. Cost-effectiveness;
7. Market readiness;
8. Technical feasibility;

9. Network benefits and grid services (e.g., peak load reductions);
10. Appropriate fit within current and anticipated regulatory constructs.

Programs and offerings that satisfy some or many of these criteria were evaluated for inclusion in the Plan, and those investments that yield positive value and offer customer benefit are included in the Plan.

7.1.2 Alternative Approaches to Financing

The Company has two primary means by which to pursue alternative approaches to financing investments needed to achieve the Commonwealth's clean energy and climate goals beyond traditional cost recovery from all customers—namely reliance on the Department's Provisional System Planning Program (i.e., CIP fees) and pursuit of federal cost-sharing or other funding for relevant projects.

The Department, in November 2021, issued Order D.P.U. 20-75-B, Order on Provisional System Planning Program (PSP). The PSP provides a new framework for planning and funding essential upgrades to the electric power system to foster timely and cost-effective development and interconnection of DG (i.e., solar and ES). The provisional framework allowed the EDCs to file certain electric infrastructure upgrade proposals with the Department that limit the interconnection costs allocated to these DG facilities. Under the provisional design, distribution load customers would fund the initial construction of these infrastructure upgrades, but these distribution customers would be reimbursed over time from fees charged to DG facilities that are able to interconnect due to the upgrades. These fees are specific to the Capital Investment Project (CIP) area, which is an electrical area with inter-dependent substations specifically interconnecting the applicable DG. Additionally, a portion of the costs of the infrastructure upgrades commensurate with demonstrated benefits are allocated to distribution load customers and excluded from the CIP fee.

The Department's initial program under Department Order No. 20-75-B provided the Company with authorization to propose CIP fees in up to eight identified planning areas, of which the Company determined five were suitable candidates. Pending Department approval, the Company's proposed CIPs will enable $232 million in distribution system investment, creating 338 MW of DG hosting capacity, 107 MW of which is additional to the Group Study participants. Approval of the proposed investments and CIP fees is vital to advancing DG projects in the Company's interconnection queue to meet the Commonwealth's clean energy goals. The Company developed the proposed Future Grid investments assuming the pending CIP investments are made.

At this point in time, the Company is currently processing multiple Group Studies for DG projects seeking to interconnect to the Company's network, and more such studies are likely. The best way to address the constraints on the distribution system for DG is to extend the PSP's CIP approach to additional Group Studies. New CIP proposals will be made at the Company's discretion. This approach of extending the CIP proposal and cost allocation methodology will provide the fastest and smoothest path to establish the capacity that DG projects need to connect to the system, at the locations where they want to connect.

The Company did consider alternative cost allocation approaches for Future Grid investments in developing the Plan, but it concluded that the approach proposed provides a fair, practical, and effective way to support electrification. In particular, cost allocation that would present barriers to beneficial electrification would work at cross-purposes to the Commonwealth's clean energy and climate goals.

The Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA) provide extensive federal funding, tax incentives, and loans for clean energy infrastructure and production.

The IIJA appropriates more than $62 billion to the U.S. Department of Energy (DOE), including funding to support electric infrastructure investments. The Company has submitted an application for competitive federal cost-share funding for a technology innovation project (Future Grid project) that would help support the proposed investments included in Section 6.3. For transmission system investment, the Company's Greener Grid Brayton Point project proposes to construct two new substations to create an onshore hub to enable greater points of interconnection for offshore wind in southeastern Massachusetts, as part of the larger Cleaner Grid New England Project submitted to DOE by the Commonwealth for federal matching funding.

The IIJA funding opportunities will continue in multiple rounds over several years, and the Company will monitor opportunities, including opportunities for joint proposals in partnership with the Commonwealth and other key stakeholders, and submit additional applications in future years for certain investments that could qualify for funding. Moreover, the Company will explore opportunities beyond competitive matching grants as appropriate—e.g., in a recent development for the utility industry the IRA has provided an infusion of new funding into the DOE Loan Programs Office for electric transmission and distribution investments that improve reliability and support electrification.

7.1.3 Customer Benefits

The 2022 Climate Act at 92B (b), 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 Company has put forth an investment portfolio that is aligned with the 2022 Climate Act and is also focused on delivering benefits for all customers. In addition to previously approved investments, the incremental investments deliver benefits that will support long-term value for customers and enable the delivery of the public policy priorities of the Commonwealth. The Company is working towards a net benefits assessment, including qualitative and quantitative benefits (where available) to customers which it will file with the Department in January.

Safety: The Company is serious about safety. The professional safety protocols it employs support its regulatory and operational goals, its legal and customer obligations and its drive toward world class performance. The Company wants to be a recognized leader in the development and operation of safe, reliable and sustainable energy infrastructure. To achieve this, the Company needs to ensure excellent levels of safety. Its Guiding Principles of Safety establish minimum safety guidelines for all Company employees to follow to avoid accidents and promote a safer environment. Investments to replace poor condition assets, which are often aged, enable us to improve the risk profile of the Company's assets, by replacing them with more reliable and more current technology. All the Company's investments adhere to its equipment standards and work methods which ensure worker and public safety.

Grid reliability and resiliency[4]: The five-year investment plan places a high priority on investments that will improve reliability and resiliency, taking into consideration the added challenges associated with climate change. This includes investments to replace aging infrastructure more prone to failure; distribution automation to support a self-healing grid designed to reduce the impact of outage events; and hardening of areas with repeat poor performance. The Company's plan for 2025-2029

[4] Resiliency investments are core investments of the Company that are included in this plan to provide a complete view of the Company's investment plans.

includes investments to expand and accelerate the FLISR program systemwide. These reliability investments target improvements in the Company's existing SAIDI, SAIFI and CAIDI metrics. Further, as described in Section 10, the Company has developed a resiliency strategy to focus on hardening investments to increase resiliency of the distribution system. In addition to its reliability and proposed resiliency programs, the Company's exploring potential projects through the resilient neighborhood program to provide resiliency benefits to the communities in which projects will be located, thereby enabling those communities to better respond to, withstand, and recover from adverse situations from climate change. The Company's AMI program will have additional benefit with respect to shortening the duration of major outages by providing greater situational awareness and providing automated outage notifications.

Facilitation of the electrification of buildings and transportation: Investments to expand electric distribution infrastructure, including substations and distribution lines, are foundational clean energy enablers, creating adequate supply to meet the needs of customers transitioning to electric transportation and heating. Absent the Company's investment plan, customers throughout the service territory will soon start to experience barriers to electrification. As described in Section 5, the Company has forecasted the expected loading associated with electrification, including heating and all classes of electric vehicles, taking into consideration the offsetting impacts of flexible demand. These needs form the basis of the five and ten-year investment plan for capacity growth. As a result of the plan, at the end of the 10-year period, the Company will have increased the headroom of the system to accommodate a 21% peak load increase across its service territory. This effort will be complemented by the Company's energy efficiency and DR programs that work to minimize loading from new and existing buildings. It will also be complemented by managed charging programs that minimize the loading impact of electric vehicles added to the system. These programs will be coordinated with the Company's introduction of AMI as a tool to empower customers to actively participate in clean energy programs, including TVR. As enabling investments supporting electrification, the impact of these programs will include a measurable reduction in the Commonwealth's carbon emissions.

Integration of distributed energy resources: The Company advocates and supports improving the interconnection process and implementing projects to facilitate the integration of DERs on its system. The Company's group study / CIP initiative addresses the barriers to interconnection associated with studying DER interconnections under the cost causation principle. With limited hosting capacity at many of the key stations where customers are interested in interconnecting, an individual project would very quickly trigger substantial substation upgrades. If an individual project cannot pay for the upgrades, this leads to withdrawals and potentially stalls DER development in the region. The Group Study and CIP proposals address a cost barrier to DER interconnection by fairly allocating upgrade cost to all customers who benefit from the upgrades, including distribution customers. In total, the Company's existing and proposed CIP initiatives will add an incremental 0.5GW of substation hosting capacity to enable DER interconnection. In addition, the Company's other non-CIP substation upgrades will add an additional 0.9 GW of hosting capacity. Other initiatives aimed at DER integration in the Plan include the Company's proposals to:

- Continue to scale and expand capabilities for flexible connections beyond its initial ARI pilot to enable accelerated network access options to reduce interconnection cost and time for solar, ESS, and EVs.
- Accelerate pathways to procure and manage DERs flexibly on the network to provide grid services that help address distribution system constraints, provide reliability, and defer and/or avoid network investments as NWAs. These programs are intended to provide incremental incentives to new and existing facilities for the value they provide to the system, including dispatchable ESS.

Avoided renewable energy curtailment: The benefits described above related to DER integration will also help avoid renewable energy curtailment. Prior to entering into an interconnection agreement with a DER facility, the Company conducts impact studies to determine what, if any, system modifications will be needed to avoid the facility having an adverse impact on the distribution system. In some cases, interconnecting customers may choose an option to curtail output in certain hours to avoid triggering the need for more extensive distribution system upgrades. With increased system capacity due to the Company's CIP and other system upgrades, there will be fewer instances where facilities trigger the need for extensive system modifications and thus the option to be curtailed due to voltage or capacity constraints. Further, the Company's plans to scale Flexible Interconnections as part of its DERMs proposal in the Plan, will enable operating agreements to be established that reduce the number of hours a facility will require curtailment.

Reduced GHG emissions and air pollutants: The Company's five- and ten-year plans allocated significant investment to initiatives that will directly and indirectly contribute to the Commonwealth's GHG emission reduction goals.

Avoided land use impacts: The Company has a longstanding commitment to controlling the environmental aspects of its activities, assuring compliance, and improving environmental performance. Achieving a balance between environmental, social, and economic sub-systems is considered essential in order to meet the needs of the present without compromising the ability of future generations to meet their needs. Societal expectations for sustainable development, transparency, and accountability have evolved with increasingly stringent legislation, growing pressures on the environment from pollution, inefficient use of resources, improper waste management, climate change, degradation of eco-systems, and loss of biodiversity. The Company must also address the challenge of restoring the natural environment. Using its own land and working with partners, the Company has an opportunity to cut carbon and restore nature at the same time. The Company will improve the natural environment on the Company's own land; for example, by protecting habitats and increasing biodiversity.

Customer benefits associated with major investments in the five-year plan (both in-flight and incremental investments) are summarized in Exhibit 7.3 below. Many of these benefits are difficult to quantify in separate dollar terms, yet they are essential to enabling the delivery of many of the quantified benefits. Overall, the Company believes that the Future Grid Plan delivers substantial net benefits to customers.

Exhibit 7.3: Customer Benefits from In-Flight and Future Grid Plan Incremental Programs/Technology Investments and Customer Programs

Incremental Program / Technology Investment	Customer Benefits
AMI	$700M+ in quantitative customer benefits across avoided O&M costs, avoided AMR meter costs, customer benefits associated with energy usage shifting and reduction, in part due to TVR, and societal benefits associated with GHG emissions reductions. AMI will provide customers with enhanced understanding, choice, and control over their energy usage, enabling possible reductions in total bills.
Grid Modernization	$300M+ in quantitative and qualitative customer benefits across avoided O&M costs, avoided capital costs, customer benefits associated with energy savings and reliability, and societal benefits. The GMP is a four-year investment plan for the years 2022-2025 for grid-facing investments. The GMP is designed to achieve the Department's grid modernization objectives to: (1) optimize system performance by attaining optimal levels of grid visibility, command and control, and self-healing; (2) optimize system demand by facilitating consumer price responsiveness; and (3) interconnect and integrate DERs.
EE, DR, EH	The programs in the current 3-Year EE Plan lower customers' bills, make their homes and businesses more comfortable, lead to net societal benefits of $6.54 billion, and lead to emissions reductions of 454,000 metric tons of CO_2e. They also contribute toward deferring or even avoiding the need to

	construct and maintain additional distribution and transmission infrastructure to serve participating customers.
Clean Transportation Programs	The customer benefits for the Company's EV programs are centered around increased adoption and access to EVs and EV charging. In alignment with the Commonwealth's goals of over 200,000 EVs on the road by 2025 and over 900,000 by 2030, as well as the targets for medium- and heavy-duty vehicles prescribed in the ACT Rule. The Company's customer EV programs give customers the support they need to build out EV charging, electrify their transportation, and manage their charging behavior, all while offering something for everyone to ensure no customer is left behind in the EV transition.
Enhanced Billing	The ability to bill customers efficiently on TVR will allow for providing improved price signals to traditional DR programs. Additionally, TVR provides an economic incentive to encourage adoption of traditional DR technologies as well as new DERs, such as behind-the-meter ES, that can provide valuable contributions to DR programs. TVR will also allow for more creative DR program design in the future, leveraging advanced rate structures or more geographically granular peak reduction programs, including potential for DER-specific rates.
DG Interconnection Automation	Automation, modified customer application and billing interfaces, as well as administrative capacity to manage improvements are required to address timely DER interconnection and customer enablement.
Flexible Connections for EVs	Rapidly accelerates transportation electrification, particularly for the MHDEV sector, by allowing fleet operators to electrify before waiting for grid infrastructure upgrades. Accelerates the GHG and criteria pollutant reductions associated with electrifying those fleets. Brings near-immediate benefits to nearby communities (particularly EJCs, in which many fleets are located).
Targeted EE and DR as NWAs	Reduces total system costs for all customers, defers or avoids the impacts of infrastructure upgrades on neighboring communities, and provides financial benefits to participating customers.
VPP as NWA	Customers gain the perceived and actual convenience of increased reliability and resilience. Customers lower energy bills due to reduced demand during peak, with an opportunity to earn revenue via arbitrage for dispatching batteries in support of local peaks. Customers will experience seamless functionality of behind-the-scenes DERMS supporting their normal usage habits, while utilizing their DERs for grid services.
Resilient Neighborhoods Program	Provides a wide range of potential resiliency benefits to the communities in which projects will be located, thereby enabling those communities to better respond to, withstand, and recover from adverse situations from climate change.
Fault Location Isolation Service Restoration (FLISR)	Distribution Automation, commonly referred to as FLISR, is a control scheme that incorporates telecommunications and advanced control of key switching devices. This scheme provides remote monitoring and operator control of field devices for normal operations and maintenance, while at the same time providing an automated response to system contingencies. This automation scheme positively impacts the resulting customers interrupted and CMI performance from a fault event that occurs within the zone of protection. Using the ICE Calculator,[5] the Company estimates the annualized benefits from implementing FLISR range from $75m-$80 million once deployed on all targeted feeders.
VVO	Through VVO, the Company manages the voltage levels and reactive power to better manage delivery of power to customers. Utilizing VVO with CVR technology can flatten and lower feeder voltage profiles based on real-time system performance. This lowering of feeder voltages benefits customers by reducing customer demand and energy use. Customer benefits are realized through reduced costs for electric energy and system capacity, which result in lower customer energy bills.
Advanced Monitoring	Feeder Monitors improve grid visibility and assist with determining outage locations and damages helping the Company route its crews to impacted locations, which benefits customers. Improved feeder visibility will help the Company more efficiently plan system needs, using direct time interval feeder data, instead of annual and peak usage data, to reduce capital investments needed. All customers will benefit from this investment, including LMI customers and EJCs.
Early Fault Detection (EFD)	The EFD System creates efficiencies of workflow and dispatch that help manage controllable costs along multiple points of overhead operations. With the proactive detection of incipient fault approach to emerging failures, the cost of response and replacement of the faulted assets is proactive. Customer interruption is avoided, and operation is planned and more efficient, therefore reducing cost to the Company and to the customer.

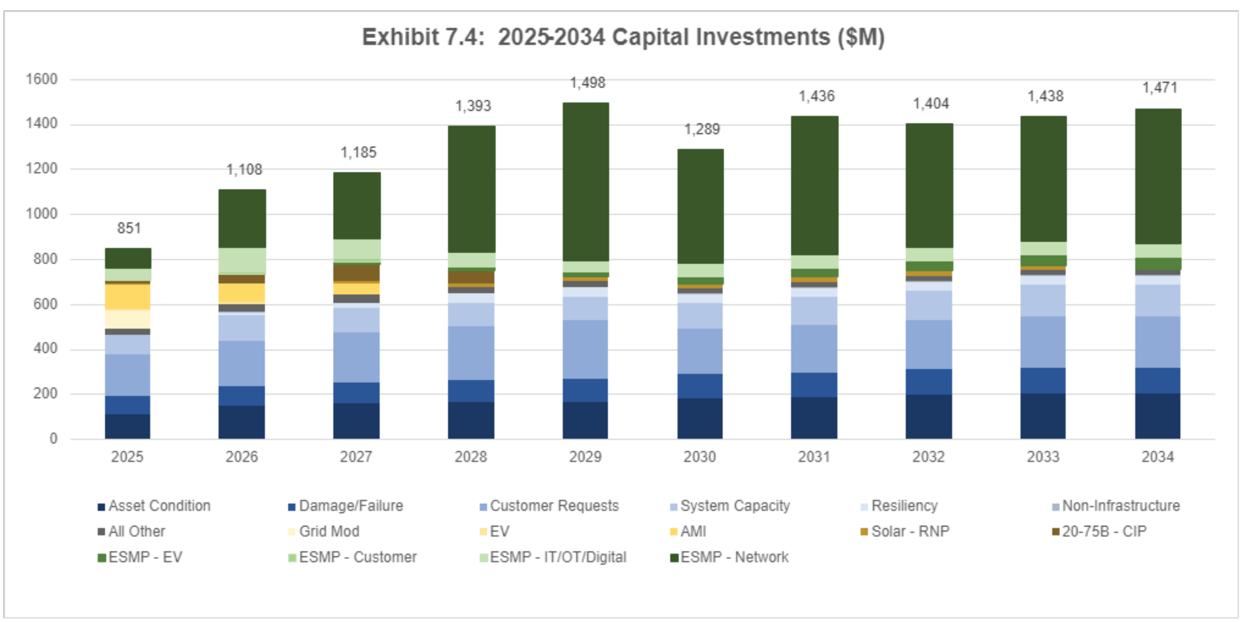
[5] The Interruption Cost Estimate (ICE) Calculator model developed by Lawrence Berkeley National Laboratory (LBNL) is an on-line tool that allows electric reliability planners to estimate customer interruption costs based on location, System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), customer mix, the distribution of outages by time of year and other factors.

Integrated Energy Planning (IEP)	This will inform the gas utility planning processes and will pave the way for initial information sharing on the status of the 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 (i.e., locations where there will be network reinforcement to readily support more electric heat pump adoption), which can be used to inform review and feedback on gas utility investments and the Commonwealth's comprehensive electrification policies and programs. This information can inform the gas planning process and pave the way for some information sharing on the status of the electric system plans.
Network Capacity Upgrades	The investments in network capacity upgrades are enablers for GHG reductions, building the capacity that will support the broader policy objectives and customer adoption needs proactively. The investment plan will allow for a seamless energy transition and the broader decarbonization of transportation, heat and energy production.
IT/Digital	Technology investments are the critical enabler that allows the value of the customer and network investments to be maximized as a more complex network is being operated. The proposed portfolio of investments will deliver a wide range of realized benefits, responding quickly to market and customer dynamics, and changing regulatory requirements. These investments will enable the introduction of new technologies and solutions that address evolving customer needs.
Telecommunications and Networking	Provides a reliable, cost-effective two-way communications capability to end devices including meters, grid automation controls, field sensors, substations, field force, and customer home area networked devices. This will ensure the network meets all technical requirements for the devices and systems deployed and meets the requirements for availability, latency, bandwidth, security, and other factors.

7.2 Investment Summary 10-year chart

As shown in Exhibit 7.4, the Company's capital plan for the ten-year period 2025-2034 continues to invest in programs and initiatives to ensure safe, reliable and resilient infrastructure that enables the just transition to a cleaner energy future. Among the drivers influencing spending in the ten-year period, certain programs, including AMI, are largely complete at the end of the first five years. Spending in the second five years is more heavily driven by peak load and capacity programs.

Exhibit 7.4: 2025-2034 Capital Investments ($M)



2025-2034 Capital Investments ($M)

Categories	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Base	493	600	642	674	701	672	697	724	750	750
Active Programs	217	133	136	76	21	22	26	27	25	7
Future Grid - Network	89	252	294	560	701	505	611	551	555	601
Future Grid – IT/OT/Digital	49	108	86	64	50	60	61	57	59	60
Future Grid – Customer	4	15	15	2	1	0	0	0	0	0
Future Grid - EV	0	0	13	17	24	30	41	45	50	53
Future Grid Subtotal	**142**	**375**	**408**	**643**	**776**	**595**	**713**	**653**	**663**	**714**

7.3 Execution Risks – Permitting, Supply Chain and Workforce Challenges

As discussed earlier in the Future Grid Plan, the magnitude of work required to meet the Commonwealth's goals and to deliver the required volume of projects is significant and unprecedented. In order to ensure that the Company can deliver on the objectives outlined in this Future Grid Plan, it is critical that the Company develop a solid plan for how the Company will execute this work. There are many external factors that impact the Company's ability to execute work including availability of land, ability to secure permits, ability to procure equipment, availability of resources, and the Company's ability to manage stakeholder expectations and gain support. Any one of these factors can negatively impact the Company's ability to execute the Plan as described. While building this Plan, the Company considered these factors and is confident that the objectives it has set can be successfully executed.

The Company has developed a plan detailing how it will deliver the scopes of work outlined in this Future Grid Plan required to meet clean energy objectives, including the assumptions, portfolio risks, and mitigation plans in progress. The Company's overall approach to developing this Plan was to evaluate the risks and assumptions for each of the substation project groups in the portfolio and assign them an execution risk score. Each of these project groups are made up of many individual projects (including land purchases, substation expansion or new construction, distribution line undergrounding or overhead construction, transmission line undergrounding or overhead construction, telecom, and protection and control) required to meet the electrical need in the area.

The Company assigned each project group an execution risk score based on criteria such as need for land acquisition, environmental considerations, need for permitting, technical complexity, existing concurrent work (outside the scope of the Future Grid Plan), siting and permitting regulations, and third-party dependencies (such as a neighboring utility or generation). The cross functional team then developed project schedules detailing siting, permitting, engineering, material procurement, and construction durations required to complete each project group. The execution score assigned to a project group drove the durations for each project. More complex projects will require longer durations due to a need to find land to build a new substation, extensive permitting requirements, significant transmission build (both overhead and underground), longer lead times for major materials such as transformers, and potential community impact assessment. An example of a higher risk project group that would take longer to complete could involve an extensive initial siting process, purchasing new substation land in a congested area and then having to site and build several miles of underground transmission line, again requiring extensive permitting.

During 2025-2029, the first five-year period, 20 project groups are projected to be ready to go in-service. The project groups that will go into service during this period are generally ones that have less execution risk and can be done in a quicker timeframe. During this first five-year period, in addition to working on these 20 projects that will go in-service, the Company will start activities on many of the remaining projects (for example the Company may begin its land search and purchasing, or engineering). Additionally, the Company will be looking for ways to optimize its delivery process and seeking other innovative solutions that it can implement to help reduce schedule risks. The Company will look at things such as developing standard engineering designs, streamlining the capital delivery process, partnering with communities to ensure they can provide feedback into the siting process, and working with the Energy Facilities Siting Board (EFSB) to find ways to streamline permitting durations.

To execute the plan as laid out above, the Company made a set of assumptions around core critical activities. There are risks associated with each of these assumptions as described below.

EFSB Approval Process Timeline: Many of the proposed projects will require extensive permitting including approval of the EFSB. Based on recent projects, the Company assumed a timeline of three years from filing to approval of a new EFSB permit. The EFSB has a desired target of one year to complete and issue permits; however, due to resource constraints and workload, the EFSB has not been able to meet this target. Based on the current scopes of work, the current project groupings would necessitate several separate EFSB approvals. In order to improve the delivery timeline, the Company would need the EFSB to be able to process the Company's applications faster than the current three-year timeframe and to process them concurrently (rather than one at a time).

If the Company's EFSB applications cannot be processed more quickly than three years or concurrently, there is a risk that the Company will not meet the schedules proposed above. The Company will discuss with the EFSB how to partner to help improve the current review and approval timeframe and if there are different ways that the Company can bundle permits or sequence submittals to improve the process. Internally, the Company will invest further in project-specific alternative exploration and analysis to determine the preferred path forward. This evaluation process may uncover ways to defer or avoid the EFSB process through alternate scopes of work.

Land Acquisition & Permitting: Many of the projects will require property acquisition in order to build out energy infrastructure. Based on the current scopes of work, the Company expects the need for many separate parcels for new substation sites along with several additional smaller property acquisition needs for expansion of existing assets. Through early engagement and partnership with impacted external stakeholders, the Company will be able to secure the necessary land parcels needed to build new substations and obtain necessary permits in a timeframe that supports the Company's schedules.

If the Company cannot secure the land for the new substations or obtain the necessary permits for the substations or transmission and distribution lines, there is a risk that the schedule proposed above will not be met. After performing a review of the areas where these substations are required, the Company believes that it is possible to locate the required substations where they are needed, but it may be challenging due to congestion, limited availability of land, or permitting challenges.

Community resistance to substation land purchases, new transmission overhead or underground lines, new distribution overhead or underground lines, or substation construction could cause a significant delay to the project schedules and impede the Company's ability to execute a project.

To manage the risk of not being able to find land in the timeframe required to support the schedules, the Company will put together a dedicated team focused on the identification and preliminary assessment regarding siting and purchasing considerations of these parcels of land. This will allow the Company to work with its Customer and Community teams to engage communities to develop a shared understanding of the needs, benefits, and impacts.

Major Materials: The Company is seeing an increased lead-time for major materials. For example, power transformers lead times can take three years from order to delivery. The Company will work with established and new manufacturers to secure long-term contracts and a pipeline of production slots that can meet the increased demand for major materials such as power transformers, control enclosures, steel structures, circuit breakers, and switches.

There is risk that the Company will not have the major materials in the timeframe required to support its construction schedules. Utilities across the country are embarking on large-scale infrastructure investment programs which also require large quantities of materials in the same timeframe. To mitigate this risk of market competition, the Company is laying out a forecast of major materials by year and will be working with existing and new manufacturers to partner on the future orders and commit to necessary production slots over 10+ years.

Resources: The Company already has ongoing strategic workforce planning efforts underway to assess and plan for the incoming project workload given the Future Grid Plan and industry projections (See Section 12). However, as mentioned earlier, given the magnitude of workload that is anticipated, the Company foresees this to be one of the major deliverability challenges.

The Company will have strategic discussions with existing and new construction contractors and engineering firms, which will enable the Company to partner with them to find ways to complete all the work in this Plan in a timeframe that supports the Company's schedules. The Company will also work diligently to recruit and hire the necessary internal resources required to support this Plan.

If the Company cannot secure the necessary resources (internal and external), there is a risk that it will not be able to complete the plan in the scheduled timeframe. To mitigate this risk, the Company is providing long-term visibility and forecasting to its contractors and conducting strategic discussions with engineering and construction firms to discuss approaches to completing all this work as proposed in this plan. The Company will explore various contracting strategies, including Engineering, Procurement, and Construction (EPC) strategies. The Company will also work with its affiliated utility colleagues in New York, who have a large-scale transmission program underway, to share best practices and see what can be applied to the Future Grid Plan portfolio of work. The Company is also developing internal hiring strategies for the necessary resources to support this Plan. The Company anticipates an industry-wide risk in this area that other utilities may face, which emphasizes the importance of starting bottom-up workforce programs now to get the emerging generation into the energy field. Support from the GMAC on this effort is welcomed.

Optimize Delivery Processes: The Company will find ways to optimize its engineering and project delivery processes so that it is able to find efficiencies in schedules.

If the Company cannot find ways to optimize delivery processes, there is a risk that it will not be able to accomplish all the work laid out concurrently. To mitigate this risk, the Company is looking at strategies such as developing new engineering design standards, streamlining its process to deliver capital projects, standardizing its equipment specifications and streamlining the procurement and contract management processes. Additionally, as some of the more complex projects progress through the process, the Company will continue to explore innovative solutions that could reduce the permitting requirements and shorten durations.

Section 8

2035 - 2050 Policy Drivers: Electric Demand Assessment

This section describes the results and methodology for the 2035-2050 electric demand assessment used by the Company, including discussions of electric heating and transportation and DER adoption.

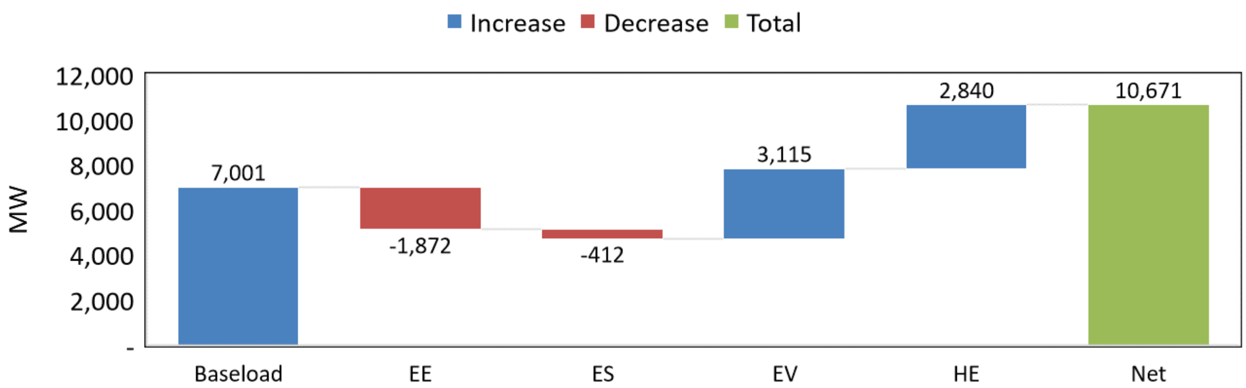
Key Take-Aways

- The Company's demand assessment to 2050 aligns with the Commonwealth's Clean Energy and Climate Plan and its preferred 2050 net zero pathway.
- Looking farther out in time, the level of uncertainty increases given the range of potential economic, technological, market, and policy drivers at play in projecting electricity demand out to 2050.
- The Company has modeled a wide array of long-term demand scenarios. Even under the lowest demand scenario, beneficial electrification leads to a more than doubling of peak demand versus today by 2050.
- The Commonwealth's goals for heat electrification mean that winter peak surpasses summer peak demand by 2036 as heat pumps become a dominant demand growth driver.

8.0 2035 - 2050 Policy Drivers: Electric Demand Assessment

Summary: The electric demand assessment shows that electric demand will more than double between today and 2050 (see Exhibit 8.1) to achieve the Commonwealth's climate goals via the "All Options Scenario" in the CECP. The increase in load is primarily driven by beneficial electrification in the transportation and heating sectors. EH also causes the system to switch from summer to winter peaking in the late 2030's. Solar PV, which has had a substantial impact in keeping demand roughly flat in recent years, has minimal impact on peak demand in 2050 because the peak is projected to switch from the summer afternoon to the winter in the evening when there is little sun.

Exhibit 8.1: Annual Peak Load Components by 2050

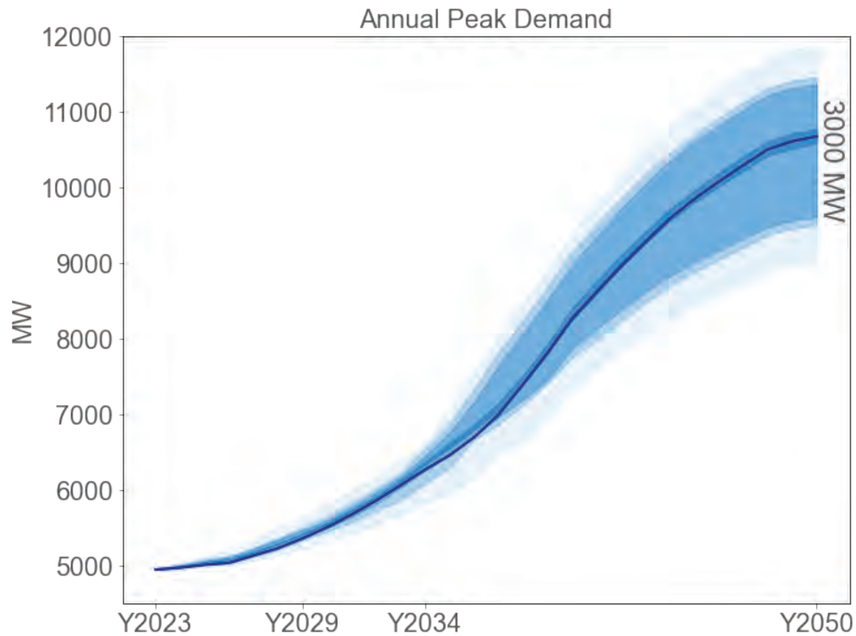


Methodology: The same methodology that was used in the demand forecast (Section 5) was applied to the electric demand assessment; however, multiple scenarios were run to generate a range of possible outcomes to address uncertainty when looking so far into the future.

Uncertainty: There is much uncertainty about what electric demand will look like in 2050. Electrification of the heat and transportation sectors currently has relatively low penetration so empirical data that is critical for building demand profiles, adoption rates, and propensity models is limited leading to uncertainty in key assumptions. The level of potential technological improvements to transportation and heating electrification technologies remains unknown. The impact and scale of programs that are not yet widespread such time varying rates and managed EV charging are uncertain. The Company has generated many demand assessment scenarios to address these uncertainties, and these scenarios show a range of possible outcomes for demand growth by 2050. As shown in Exhibit 8.2, the difference between baseload and net peak load is roughly 3,000 MW or approximately 30% of expected demand under the "All Options Scenario" from the CECP in 2050.

The expected long-term demand growth and the associated range of uncertainty will change over time. As penetration of new technologies, including beneficial electrification of heat and transportation, increases and these technologies mature there will be more empirical data on how people are adopting and using these technologies. With new information, the demand assessments produced in future years could have higher or lower expected demand, and uncertainty about expected demand may decrease. As the Company invests in new capabilities to enable flexible load resources, including EV managed charging, TVRs, aggregation of DRs, and flexible heating demand, there is the opportunity to "bend the curve" on electricity demand growth toward the lower end of the range of uncertainty.

Exhibit 8.2: Winter Peak Load Forecast



Validation: The Company benchmarked its Demand Assessment against the CECP report. The underlying assumptions for the DERs in the Company forecast align with the targets in the CECP "Phased" pathway. The CECP Pathways Analysis[1] shows an approximately 120% increase in peak demand between 2020 and 2050 which is comparable to the Company's demand assessment of 110% growth over the same time –period and within the uncertainty range shown in Exhibit 8.2, validating the Company's work aligning with the CECP.

The validation against the CECP underscores the fact that meeting the Commonwealth's clean energy and climate goals requires quickly ramping up electricity distribution infrastructure capacity to serve a peak demand that will increase substantially due to beneficial electrification.

8.1 Review of Assumptions and Comparisons across EDCs

The electric distribution companies (EDCs) in Massachusetts made up of Eversource, National Grid, and Unitil together have reviewed and compared overarching assumptions specific to future electric demand assessments across the Commonwealth. The overall strategy employed by each individual EDC shares many similarities, in particular applying and assessing the impact of state level electrification and clean energy scenarios for the buildings, transportation, and energy sectors. The EDCs adopt a scenario-based load assessment methodology and develop DER scenarios from the different decarbonization scenarios or 'pathways' outlined in the Massachusetts 2050 Decarbonization Roadmap[2] (the 2050 Roadmap) and the Massachusetts Clean Energy and Climate Plan (CECP) for 2025 and 2030.[3]

[1] https://www.mass.gov/doc/clean-energy-and-climate-plan-for-2025-and-2030/download
[2] https://www.mass.gov/doc/ma-2050-decarbonization-roadmap
[3] https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030

For the heating electrification sector, Eversource looks at scenarios from an independent study of the 2050 Roadmap that was conducted as part of the DPU MA 20-80 Docket,[4] named the "Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals" report (or "Future of Gas" report). The study generated electrification projections for the 'All Options' pathway (known as 'High Electrification' in the DPU study) and other scenarios with updated assumptions specific to building transformations. Eversource is focusing its efforts for electric demand assessments on four scenarios: High electrification ('All options'), Hybrid Heating, Targeted Electrification, and Networked Geothermal. National Grid looks at the Phased scenario, the Full Electrification scenario, and the Hybrid scenario outlined in CECP. Unitil's building electrification forecasts are based on the number of residential customers served and average home size and an assumed btu/sqft for heating and air conditioning as well as demand assumptions for residential gas customers that could convert gas appliances (range and dryer) to electric. Commercial/Industrial electrification forecasts are based on existing gas usage.

For the energy efficiency outlook, the EDCs assume that energy efficiency offerings continue in line with historic trends. For DR, National Grid assumes company programs continue. Eversource and Unitil currently do not consider demand response applications (see Section 8.2.4).

For the transportation electrification sector, Eversource looks at the same independent study as discussed in the above heating electrification sector. Transportation sector electrification is consistent across the multiple scenarios in the study and is based on the high electrification scenario/assumption. National Grid evaluates the load impacts of scenarios from adopting the California Advanced Clean Car (ACC II) Rule and Advanced Clean Truck Rule. Both rules have been adopted by the State of Massachusetts[5] and yield scenarios that align with the State's decarbonization pathway. Unitil compared the details of its demand assessment (i.e., quantity of EVs, heat pumps, solar and energy storage) to the "All Options" pathway to ensure the demand assessment was in line with the decarbonization goals of the Commonwealth.

For DG, the EDCs assess the "All-Options" scenario outlined in the 2050 Roadmap. This scenario is described as one that "selects the most economic resources to meet emissions limits using baseline cost assumptions". It provides an outlook on connected solar capacity, including both rooftop and ground-mounted, through year 2050. Eversource is actively researching the penetration and viability of long-term energy storage solutions in its territory. National Grid and Until assume energy storage aligns with the 'All Options' pathway outlined in the 2050 Roadmap.

8.1 Buildings: Heating Electrification and Energy Efficiency Assumptions and Forecasts

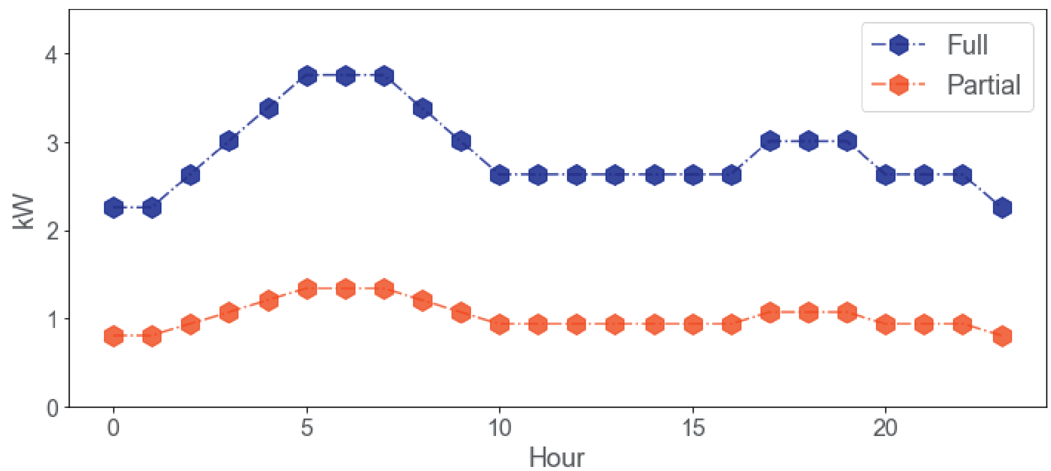
8.2.1 Technology Assumptions

The Company considers full EHP systems and partial EHP systems in the electric demand assessment process. A full EHP system is assumed to serve all the heating in the home or building. A partial system is assumed to have alternative fuels available as a supplement when it is very cold. This load assessment process assumes existing legacy heating fuel (i.e., delivered fuels and gas supplied via gas utility networks), as the supplemental fuel. The load impact is based on the seasonal energy consumption of each. Then, the winter seasonal energy consumption is proportionally allocated to the heating-needed months including all winter months (i.e., November to March) and some shoulder months (October, April, and May) based on a heating demand profile

[4] https://thefutureofgas.com/content/downloads/2022-03-21/3.18.22%20-%20Independent%20Consultant%20Report%20-%20Decarbonization%20Pathways.pdf
[5] https://www.mass.gov/regulations/310-CMR-700-air-pollution-control-0

from analyzing the Company's natural gas heating customer heating energy consumption. Exhibit 8.3 presents a typical winter day for an EHP average load consumption profile for full and partial EHP, respectively. Both profiles show a morning usage spike and a moderate evening usage increase reflecting the interactions of cold weather and people's activities – i.e., the morning spike coincides with people getting up in the morning when the temperature tends to be lowest for the day, and the evening increase coincides with people arriving home in the evening. Such a profile has been compared with ISO-NE's empirical study[6] and shows similar expectations regarding the shape and the magnitude of the load impact.

Exhibit 8.3: Typical Winter Day for EHPs

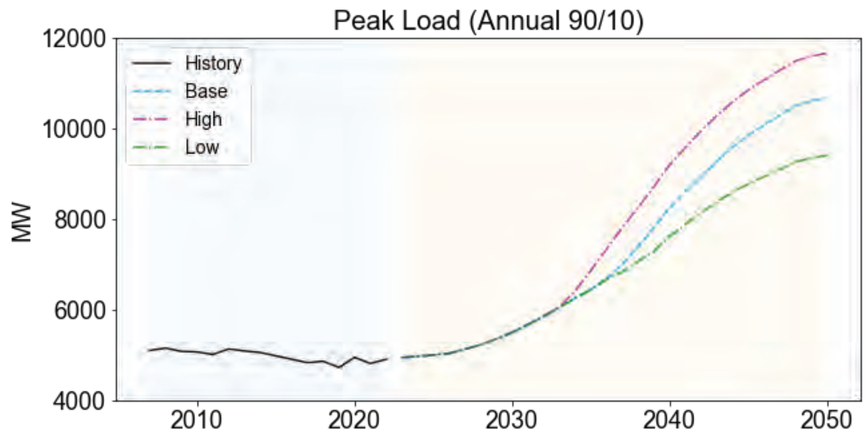


8.2.2 Adoption Propensity Assumptions

The Company considers three EH scenarios (i.e., Base, Low, and High) with each of them modeling the trajectory towards meeting the State's CECP "Phased", "Hybrid", and "Full Electrification" pathway[10] target by 2050, respectively. The Base scenario assumes adoption of both partial and full EHP systems and allows for hybrid fossil-fuel and EHP systems aligning with the State's assumption for the "Phased" scenario. The High scenario assumes more rapid adoption of full EHP systems and results in higher full EHP penetration through 2050, which aligns with the State's assumption for the "Full Electrification" scenario. The Low scenario presents a case where hybrid utilization of fossil-fuel and EHPs is more common, aligning with the State's outlook for the "Hybrid" scenario. Exhibit 8.4 presents the estimated peak load under each of the Company's three scenarios (with DERs other than EH being the same): the uncertainty band grows wider moving further out in time, with the peak load varying up to about 2,200 MW or over 20% by year 2050. Nevertheless, even the modest electrification scenario indicates a peak load of almost double the 2022 peak load by the end of the assessment period. The EH scenario selected does not affect the demand forecast period through 2034 (as presented in section 5 above) because the difference in EHP adoption only affects peak demand once the electricity system becomes winter peaking in the late 2030s.

[6] https://www.iso-ne.com/static-assets/documents/2022/04/final_2022_heat_elec_forecast.pdf

Exhibit 8.4: Estimated Peak Demand by Heat Pump Adoption Scenario



EE will continue to grow but at a slower incremental rate, reflecting the saturation of the market and the uncertainties regarding available funding and supportive policies. There are no existing long-term quantitative State policy goals for EE development, thus the scenario development is largely based on known policies and programs and assumes a relatively flat growth in the residential sector and a slow-down in commercial sector reflecting the current highly saturated market and the competition for funding of EE programs with the EH program in terms of overall customer affordability. Overall, EE penetration is expected to follow load distribution.

8.2.3 Building Code Assumptions

The Company's demand assessment does not explicitly model building code changes. However, 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 EH, and the Company's load profile for EHP energy usage does assume building weatherization. To the extent that building code changes would drive EH adoption, the Company's demand assessment already assumes achieving the Commonwealth's goals for EH. Nonetheless, as Commonwealth building code policies promote more energy efficient buildings and the electrification of buildings, modeling the impacts of building code changes more explicitly is an area of active focus for the Company.

8.2.4 Demand Response Scenarios – Impacts on Heating Demand

As explained in section 8.2.2 above, the Company's demand assessment includes scenarios with varying levels of hybrid heating. Hybrid heating that relies on non-electric heating sources during periods of high electric demand can materially mitigate the impact of EH on peak demand. Beyond modeling the effect of hybrid heating, the Company currently does not have a load assessment scenario that models managing electric heating demand. This is owing to a relative lack of industry experience and data for estimating the potential and reliability of other forms of electric heating DR during the coldest hours for which the Company plans its network. There may be opportunities to manage peak electric heating demand in the future such as direct load control of heat pumps, thermostat control, or thermal ES; however, industry activity and data on this front are limited and often from outside of the United States. The Company faces unknowns regarding EH DR that include customers' behavior on the coldest days in response to DR, price signals or load controls, the potential "snapback" effect, and the performance of EHPs under different conditions. Nonetheless, facing the prospect of very large winter peak demand in the future, industry activity on EH DR appears to be increasing globally. The Company will monitor the market evolution and seek representative (in sample size, diversity, and historical length) sample data (e.g., AMI data) for studying demand-side management opportunities from EH.

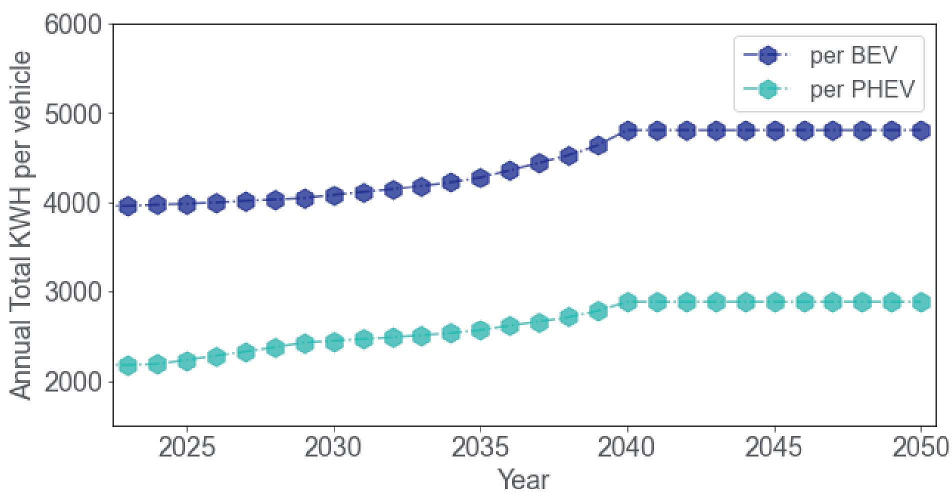
8.3 Transport: Electric Vehicle Assumptions and Forecasts

The load assessment process considers the impact of EV that plug-in to the electric system, including "plug-in hybrid electric vehicles" (PHEVs) and "plug-in battery-only electric vehicles" (BEVs). Light-duty (LDEV), medium-duty (MDEV), heavy-duty (HDEV) electric vehicles and electric buses (E-buses) are the four categories of EVs modeled in the demand assessment.

8.3.1 Technology Assumptions

As LDEV adoption rates increase, the annual energy demand associated with these vehicles, which is primarily determined by the vehicle miles traveled (VMT) for EVs, also shifts. Exhibit 8.5 shows the temporal progression of the energy demand per LDEVs in kWh throughout 2050 using data from the National Highway Traffic Safety Administration (NHTSA).[7] The VMT-driven annual demand steadily increases until 2040 and remains stable after that.

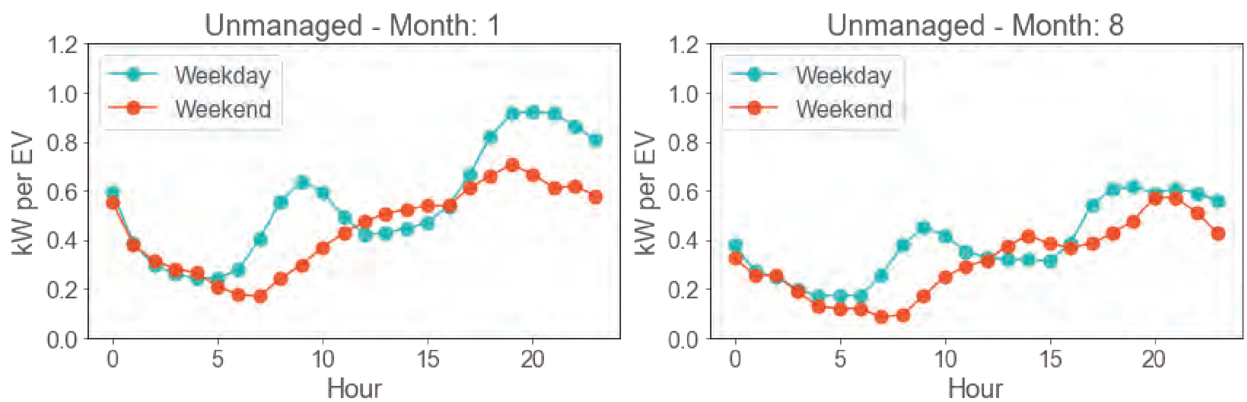
Exhibit 8.5: Temporal Progression of Energy Demand per LDEV



[7] https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/809952, retrieved July, 2022

Our assumptions regarding the temporal pattern of charging behavior leverages an ISO-NE's study[8]. Exhibit 8.6 depicts the unmanaged charging profiles of LDEVs for typical winter and summer days. A dual peak pattern is observed on weekdays with the evening peaks (between hours 19 and 21) generally larger than the morning peaks.

Exhibit 8.6: Unmanaged Charging Profiles

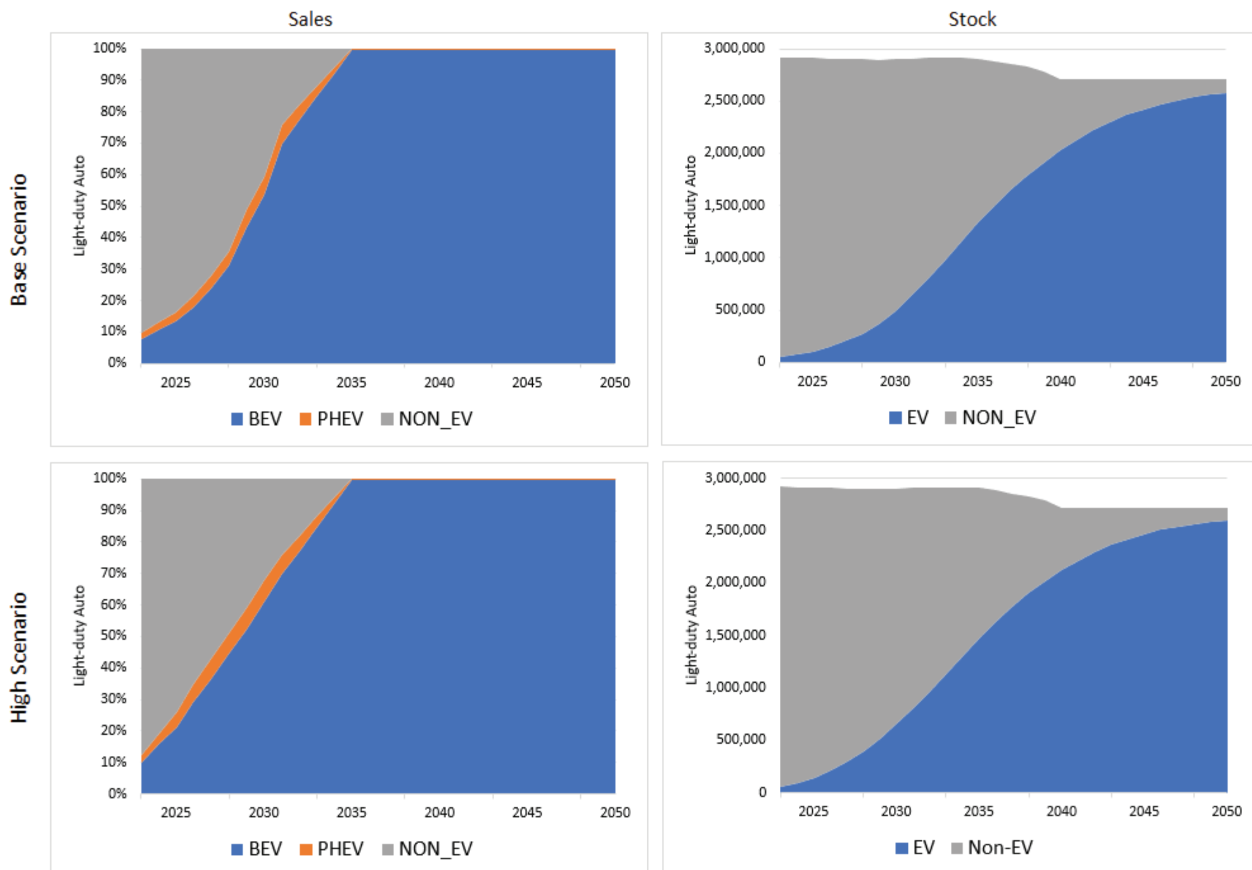


8.3.2 Adoption Propensity Assumptions

The LDEV adoption is modeled based on the Commonwealth's adoption of California's ACC-II Rule. Although the Rule require 100% ZEV sales by 2035, it also offers flexibilities to transfer ZEV "sales values" across all states that have adopted the regulations (e.g., a manufacturer can overachieve in California and underachieve elsewhere), provisions to encourage the sale of affordable EVs in EJCs, and the option to use historical ZEV sales credits to meet the annual ZEV sales targets. All the flexibility provided in the rules expires by or before the year 2031. These differences (i.e., with and without the flexibility) may lead to different ZEV sales patterns in the near term versus the longer term. The Company evaluates these two scenarios of LDEV adoption – one with the flexibilities (i.e., Base Scenario) and the other without the flexibilities (i.e., High Scenario) as presented in Exhibit 8.7. By the year 2050, both scenarios reach over 95% of EV penetration in the Company's Massachusetts service area, which aligns with the State's CECP pathways.[13]

[8] https://www.iso-ne.com/static-assets/documents/2019/11/p2_transp_elect_fx_update.pdf

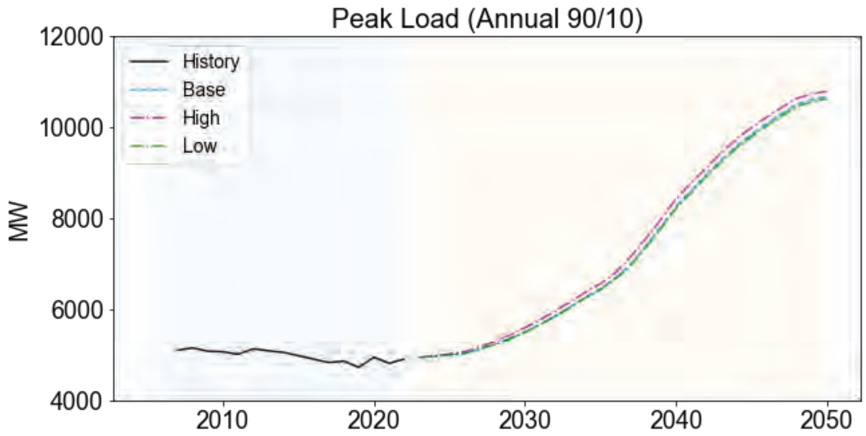
Exhibit 8.7: LDEV Adoption Scenarios



As of 2022, there are very few MHDEVs and electric buses in the Company's service territory. Because the MHDEV market is much more nascent than the market for LDEVs, there are greater uncertainties in projecting the adoption of MHDEVs and electric buses. Three different scenarios are developed for evaluating possible MHDEV and E-bus pathways: (1) the Base scenario is based on the Commonwealth's adoption of California's ACT Rule; (2) the High scenario reflects an accelerated adoption rate; and (3) the Low scenario is based on the Bloomberg New Energy Finance's (BNEF) 2022 Electric Vehicle Outlook. The penetration ranges from 40% to 100% across scenarios and vehicle types by 2050.

Although these scenarios lead to different outlooks on EV adoption, the peak load impacts are similar to those presented in Exhibit 8.2. This is because: (1) the two LDEV scenarios have only slightly different adoption outlooks in the near-term but have very similar cumulative adoption overall as presented in Exhibit 8.8 (LDEV adoption scenarios); and (2) although the MHDEV adoption varies more across scenarios, the peak hour for the overall demand is expected to be in the evening through the assessment period, which is not coincident with the MHDEV peak charging demand. Thus, the difference in total peak EV charging load is relatively small.

Exhibit 8.8: Estimated Peak Demand by EV Adoption Scenario



8.3.3 Mileage, and Time of Day Assumptions

Please refer to Section 8.2.1 Technology assumption.

8.3.4 Managed Charging Scenarios – Impacts on EV Demand

The Company's demand assessment includes a managed charging scenario that assumes 75% of the LDEV owners have access to home chargers, and 75% of those LDEV owners are assumed to shift their charging demand to the hours immediately following the peak periods (i.e., 16:00 to 22:00). Away-from-home charging is assumed to remain unmanaged. The managed charging scenario was developed based on the Company's current managed charging program and the National Renewable Energy Laboratory (NREL) EVI-Pro tool.[9] Under this EV charging demand flexibility scenario, the peak load demand is assessed to be reduced by 3.5% by year 2050 as a result of managed charging,

8.4 DER: Photovoltaic/ESS – State Incentive Driven Assumptions and Forecasts

The Company's demand assessment includes rooftop and ground-mounted PV types as outlined in the "All-Options" scenario in the 2050 Roadmap. The State decarbonization targets drive the Company's outlook on solar PV and ESS development in our service territory. The Company uses queue projects, customer demographic information, and the GridTwin[10] tool in estimating where and when projects may get developed.

8.4.1 Technology Assumptions

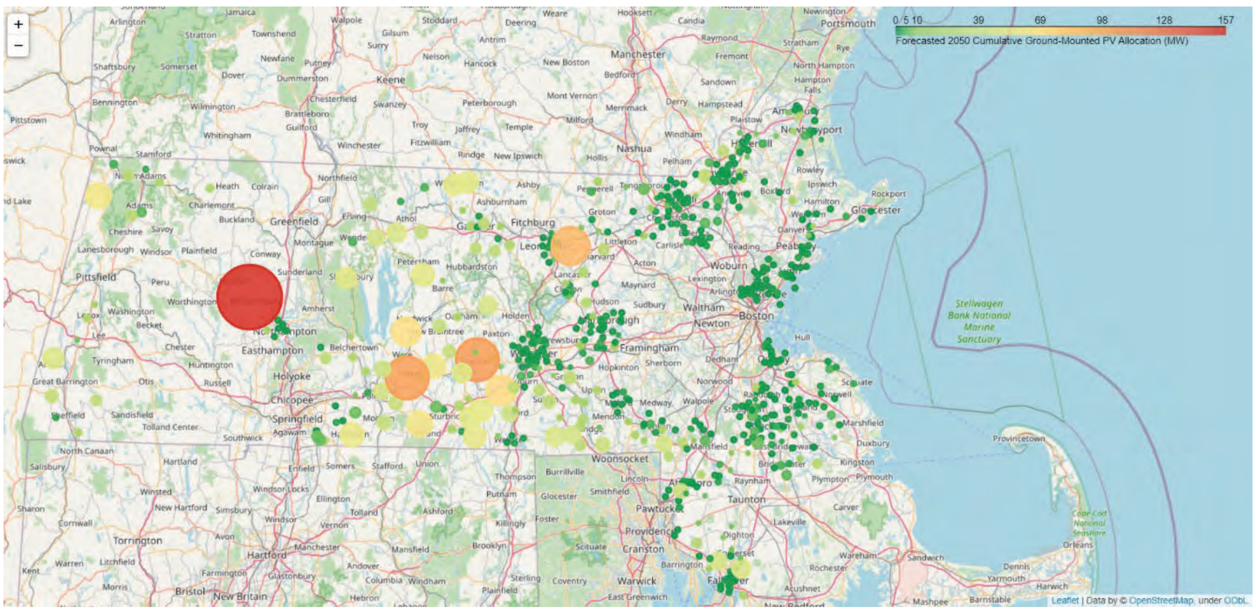
The Company's demand assessment includes rooftop/behind-the-meter and distributed ground-mounted solar PV as well as ESS systems.

[9] https://www.nrel.gov/transportation/evi-pro.html
[10] https://gridtwin.energy/

8.4.2 Adoption Propensity Assumptions

PV connection is projected to achieve the Company's share[11] of the State policy target under the All Options scenario as stated in its 2050 decarbonization roadmap[12]. The "All-Options" scenario targets 6.99 GW of behind-the-meter (BTM) PV connection and 16.2 GW of ground-mounted PV connection by 2050 for the Commonwealth. For the Company's service territory, the Base scenario models about 3.1 GW of BTM PV and 3.6 GW of ground-mounted PV. Exhibit 8.9 presents the distribution of PV under the Baseline scenario by 2050. Two alternative scenarios were also developed reaching the "All-Options" scenario policy goal a few years earlier or later to account for uncertainties. Nevertheless, EH will push the system to switch to winter peaking by the late 2030s where peak hour is expected to be in the late evening, when PV is not expected to help reduce peak demand.

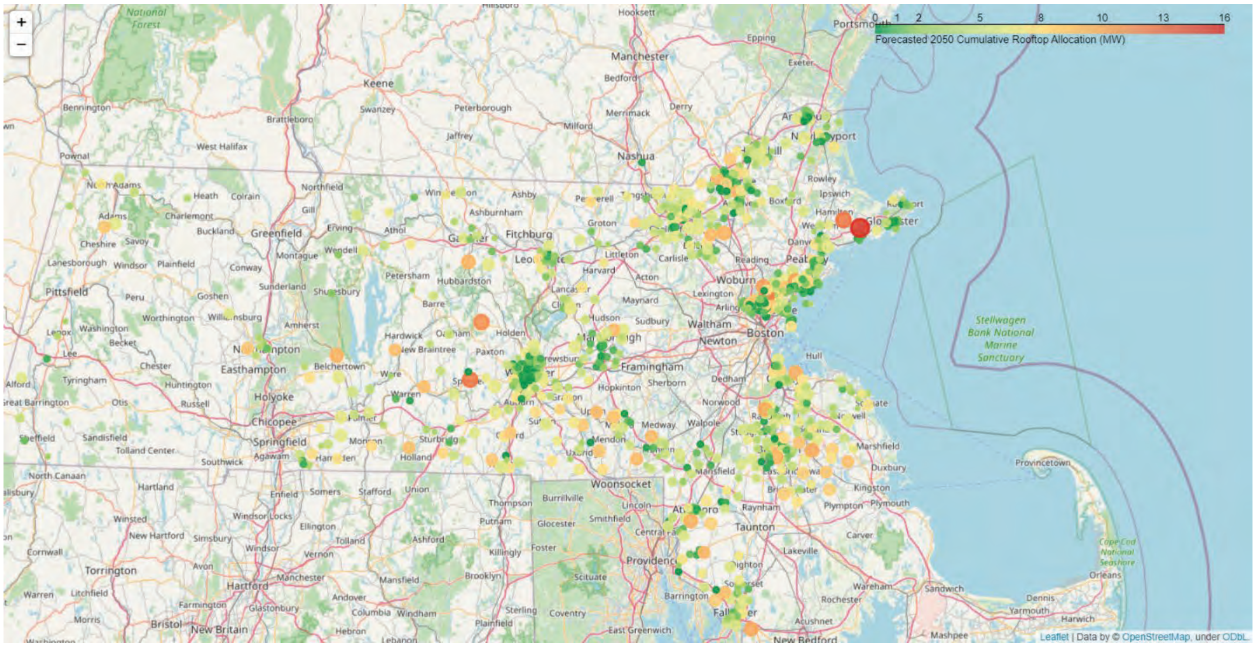
Exhibit 8.9: 2050 Ground-mounted PV Forecast Heatmap under Baseline Scenarios



[11] 45% was the share for National Grid when the SMART program opened. It was the percentage of customers National Grid serves in the State of Massachusetts compared with Eversource and Unitil. This same share is assumed for calculating National Grid share of the State's existing and planned solar goals.

[12] *Massachusetts 2050 Decarbonization Roadmap*, December 2020

Exhibit 8.10: 2050 Rooftop PV Forecast Heatmap under Baseline Scenarios



The Base ESS scenario was developed around State policy targets with assumptions on the Company's share[13] of the statewide target and the share of total ESS capacity that would be connected to the electricity distribution system[14]. The Base scenario incorporates the 2050 Roadmap's goal of1,000 MW of statewide ESS connection by 2025[15]. The 2050 Roadmap also identifies a few other ESS pathways through 2050 including reaching 3,000 MW of large-scale ESS (generation) in the "All-Options" scenario, about 4,000 MW implied in the 100% "Renewable" scenario, and about 12,000 MW implied in the "No Thermal" scenario. Most of the ESS in the State is expected to be on the bulk power system (i.e., interconnected to the transmission network) and thus out of scope for this distribution network load assessment. Overall, under this Base scenario, ESS on the distribution system is expected to continue grow in the Company's Massachusetts service territory but at a slower rate due to policy and market uncertainties. Two alternative scenarios were developed to (1) consider the case of later and smaller saturation on the distribution-level ESS market and (2) consider the case of more of the total ESS capacity interconnecting to the bulk transmission as opposed to the distribution system.

8.4.3 Time of Day Assumptions

The hourly impact of PV is simulated using the PVWatts tool[16] developed by NREL. On a sunny summer day, PV generation is expected to follow a bell-curve with maximum generation around noon time, but the exact profile depends on available sunlight and temperature at the location. The solar PV generation profile is simulated under the weather of a typical meteorological year[17].

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[13] Same as the PV share in the long-run.
[14] About 36% on the distribution system as of today.
[15] *Energy Pathways to Deep Decarbonization. A Technical Report of the Massachusetts 2050 Decarbonization RoadMap*. Page 61, December 2020.
[16] https://pvwatts.nrel.gov/
[17] https://pvwatts.nrel.gov/downloads/pvwattsv5.pdf

ESS is modeled to discharge during typical peak hour window (15:00/16:00 to 19:00/20:00 for summer and 17:00 to 20:00 for winter) and charge at other hours (primarily during daytime to coincide with PV generation hours).

8.5 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, DPU 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.[18] Several analyses have shown that offshore wind will be the linchpin of Massachusetts' decarbonization strategy – it will likely provide around 50% of the state's power by 2050. Integrating offshore wind effectively and efficiently will require meaningful collaboration with other New England states. Massachusetts is well-positioned to lead this regional collaboration on offshore wind as we look toward our decarbonized future.

Brayton Point in southeastern MA is one of the major locations where offshore wind energy is expected to come ashore. The Company has proposed a project to expand transmission infrastructure at Brayton Point and Grand Army to enable the interconnection of more offshore wind. The project will enable cost-effective integration of energy without significant disruption of local communities. Some of the benefits of the Brayton Point project include:

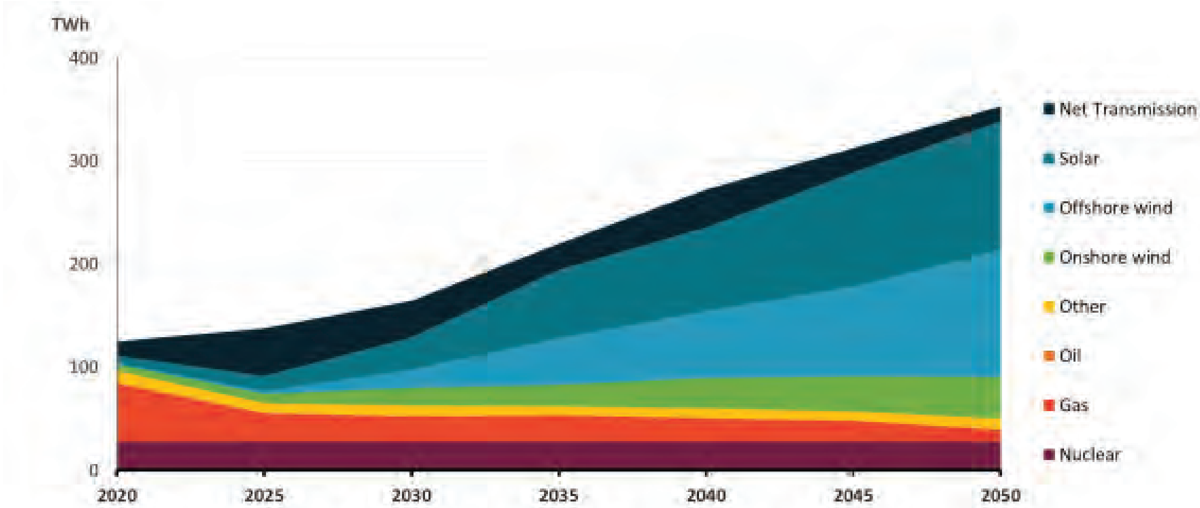
- Creating several hundred clean energy industry jobs;
- Alleviating transmission capacity constraints and congestion to allow the integration of clean energy (I.e., offshore wind);
- Avoiding the need to build infrastructure in a new location, including the need to secure new permits and engage in siting, by instead expanding and updating existing, former fossil fuel, infrastructure;
- Creating opportunities for future clean energy investments at the location; and
- Limiting disruption to local communities by building at existing Company facilities.

8.6 Currently Projected Clean Energy Resource Mix

Most of the energy delivered to customers over the Company's electricity distribution network through 2050 will come from the bulk power system. That power will be increasingly decarbonized. Exhibit 8.11 below shows how the Commonwealth's 2050 CECP projects that New England's power grid will transition to one dominated by wind and solar generation.

[18] D.P.U. 23-42.

Exhibit 8.11: New England's Electrical Generation by Energy Source[19]



Note: "Other" includes both biomass and municipal solid waste electric generation units.

[19] Mass CECP for 2050 – phased approach: https://www.mass.gov/doc/2050-clean-energy-and-climate-plan/download

Section 9

2035 - 2050 solution set – Building a decarbonized future

This section includes the Company's longer-term vision for a decarbonized electric system, including a discussion of potential future network investments, and enabling technology, programs, and policies.

Key Take-Aways

- As electrification scales up, the Company will connect EHPs, public and private EVs, ESS, and renewables at an ever faster rate. Annual peak load will increase and the widespread adoption of EH will result in a switch from summer to winter peaking around 2036.
- The Company expects to deploy more advanced and widespread load flexibility for buildings, EVs, and ESS and better management for renewables through technology and pricing to provide NWAs to manage system and local peaks without the need for infrastructure investment.
- The Company will be further transformed through the digitization of the network planning and O&M. This will allow for better engagement and services for customers, and more efficient and effective operation for the Company.

9.0 2035 - 2050 Solution Set – Building A Decarbonized Future

In Section 6, the Company highlighted the five- and ten-year planning solutions that are primarily driven by forecasted peak load growth in each sub-region, discussed in Section 5. It included EV load growth and other DER adoption. In this timeframe, EH does not yet have a significant impact on the summer peaks. However, based on the long-term demand assessment, and in alignment with the 2050 Decarbonization Roadmap outlined in Section 8, the Company expects that the winter peak will surpass the summer peak in the 2035 to 2050 timeframe for all sub-regions, with some winter peaking as early as 2035. This section discusses the infrastructure, technology and policy needs as well as forward-looking solutions needed to realize a decarbonized future while maintaining safe, reliable, equitable service for all customers.

- **Accelerating Adoption –** From 2035-2050, EH and transportation along with decarbonizing the power supply will continue to be the primary strategies for achieving the Commonwealth’s climate goals in the energy sector. It's estimated that peak demand will grow at an average annual rate of 3.4% between 2035 and 2050. This is faster than the 2.5% annual growth expected between 2025 and 2034.
- **Supporting Customers through the Transition –** The Company will continue to support customers’ transition to electric heating and transportation through incentives and enablement of EHPs, ES, EVs and programs to manage them, and will connect increasing amounts of solar and solar paired with storage.
- **Minimizing the Costs –** Focus will continue to be on delivering the clean energy transition affordably. The Company will:
    - Deploy NWAs where they provide value to customers to defer or avoid specific network infrastructure investments.
    - Prioritize EE and demand flexibility for buildings, including deploying managed control of EHPs and BTM ESS including opt-in or opt-out customer control, third-party control (e.g., aggregators), or Company control.
    - Prioritize demand flexibility for EVs including deployment of managed charging and V2G programs, including opt-in or opt-out customer control, third-party control (e.g., vehicle OEMs), or Company control.
- **Building Technology to Enable the Business –** The Company will deploy improved IT, data, and digital tools necessary to plan, construct, maintain, and operate the grid more efficiently and effectively. More digitally enabled devices connected to the electric network will be able to leverage software-as-an-asset to update devices remotely and will require continued investment in cybersecurity to protect secure operation of the system.
- **Focusing on the needs of all customers and communities –** The Company will deliver a clean, fair, and affordable energy transition by building a smarter, stronger, cleaner electric grid for all.

The solutions that the Company expects to deploy include innovative programs and strategies that must first be tested through pilots or by reviewing the experience of other utilities, and the scaling up of current programs and strategies. Implementation of solutions will depend on foundational grid investments to be made between 2025-2034.

9.1 Clean Energy Solutions Including Behind the Meter Incentive Design Scenarios

The Company will continue to listen to and adjust offerings to meet customer needs. By 2028, the Company plans to have AMI deployed across the territory and be able to fully leverage meter data for granular information on customer energy use patterns, clean technology adoption, and program engagement. Residential and commercial customer surveys will continue to be conducted to learn about perceptions, awareness, barriers, and preferences. Focus groups, direct customer feedback, and community listening sessions will also be held to develop deeper insights by customer segment. With improved customer data, the Company can better tailor products and programs in response to customer needs. The Company will be able to target programs to help customers reduce energy costs in ways that meet specific customer profiles. For example, customers can be targeted for behavior-based energy conservation programs based on the amount and timing of a customer's energy use.

The Company will continue to build on BTM programs such as EE, DR, flexible connections, EV and ESS managed charging, and TVR. To understand the full extent of benefits that can be achieved by orchestrating the operation of DERs the Company is undertaking a strategic project in partnership with MassCEC, Baringa, and Eversource that is investigating the potential value that dispatchable DER flexibility products can create for customers and the grid. This involves analysis, targeted discussions with peer utilities, aggregators, flexibility marketplace providers, and technology OEMs.[1]

9.1.1 Buildings: Winter Demand Response Scenarios

In contrast to the ten-year planning horizon, for the 2035-2050 timeframe, electric heating loads will constitute a substantial portion of the overall peak demand as the system transitions to a winter peaking scenario. This means that instead of the system's peak load being driven primarily by air conditioning load on the hottest summer days as it is today, peak load will be driven primarily by electric heating load on the coldest winter days. As described in section 8.2.4, winter DR is not currently modeled in the Company's demand assessment due to various unknowns related to the lack of collective industry experience and data for estimating the potential and reliability of electric heating DR during the coldest hours for which the Company plans its network. Despite this uncertainty, the Company acknowledges that there likely will be an important role for demand side measures to help reduce winter peak demand.

The Company expects to address the increasing electrification of load through two methods which will help manage demand:

1. Continue deploying EE measures (e.g., weatherization and appliance upgrades) to minimize overall peak demand growth, as the Company does today as a Mass Save Program Administrator.[2]
2. The demand flexibility for building programs that leverage TVR, DERMS, communications and streamlined customers billing initially deployed in 2025-2034 are all anticipated to be effective tools in helping the Company induce customer behaviors to flatten load curves

[1] https://www.masscec.com/grid-modernization-and-infrastructure-planning. Initial findings from the study were presented at the August 10, 2023 GMAC meeting https://www.mass.gov/doc/gmac-meeting-presentation-slides-08102023/download

[2] On March 26, 2021, Governor Baker signed into law Chapter 8 of the Acts of 2021, An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy (the Climate Act), codifying the Administration's commitment to achieve net zero emissions in 2050 and furthering the Commonwealth's nation-leading efforts to combat climate change and protect vulnerable communities. The 2021 Climate Act established new mandates for GHG emissions reductions by 2030 and 2040 and directed the EEA Secretary to set a GHG emissions reduction goal for three-year Energy Efficiency Plans.

and reduce increases in peak electric demand that would otherwise occur outside of more traditional DR offerings.

While summer DR has been successful, the winter events have fundamentally distinct characteristics that make DR more challenging.[3] These will need careful studying. Some potential ways to manage winter heating loads include:

- use of battery storage including V2G, or
- switching to non-electric alternative heating sources such as natural gas, low carbon gases (e.g., renewable natural gas, hydrogen), delivered fuel, biomass (e.g., wood), or back-up diesel generation.

The adoption of these approaches will present challenges, and, over the next decade, steps must be taken to address them. For the time-being, switching to non-electric alternative heating sources may offer the best intermediary solution to system peak on the coldest days, as many residential and commercial buildings are likely to be remain "hybrid" (i.e., having both electric heat pumps and a legacy heating system such as natural gas), through this period of transition.

9.1.2 Transport: Electric Vehicle Charging Demand Management Scenarios

Charge management for EVs remains an area of high importance and growing capability, yet challenges remain to ensure that its potential positive impact is achieved. Managed charging programs that are badly timed run the risk of worsening grid conditions. Effective load management techniques also need to consider the charging customer's needs and preferences.

Managing EV charging can take several forms. On-site load management, load balancing, or load-offsetting techniques can potentially apply to any EV charging site. For customers who are flexible as to when their EV charging occurs, (e.g., most residential customers), two main flavors of managed EV charging are available: Customer-driven EV charge scheduling, (sometimes referred to as "passive" managed charging), and dynamic charge management based upon signals for grid conditions or costs, (sometimes referred to as "active" managed charging).

Passive managed charging programs focus on incenting customers to change their own charging behavior. While passive programs are simple in design and easy to administer because they rely on human behavior, they may not be as effective or robust as active programs. This is why these programs are generally designed as blunt instruments to attract customer participation at scale. The benefit of these programs may be to achieve overarching system demand management, but they are not effective mechanisms to manage real time locational grid congestion constraints. These programs are designed to function more as 'set it and forget it' and their associated economic benefits are lower than more dynamic managed charging offerings.

[3] Winter DR programs face significant challenges. Firstly, the temperature difference between outdoor and indoor air temperatures during a winter peaking event, which occurs during the coldest hours of the day, is much larger than the temperature differential during a summer peaking event. For example, during a winter peak an outdoor air temperature of -5 degrees is a difference of 73 degrees from an indoor set point of 68. In the summer, by contrast, an outdoor air temperature of 95 degrees is only 20 degrees away from an indoor set point of 75. Therefore, the rate at which the indoor temperature would drop during a winter DR event would be 3-4 times higher than the rate at which the indoor temperature would increase in the summer. During the summer events, many homes can "coast" for the duration of the DR event, slowly rising in temperature to a maximum temperature as defined by the customer, only turning the air conditioner back on at the end of the event. Since the outdoor air temperature will have dropped markedly during the event, typical dispatch periods are 5-8pm, the air conditioners do not have to work as hard to return the home to temperature at the end of the event, and the magnitude of that load reappearing on the grid will not be as impactful as it would have been had they been operating during the time of the systemwide peak. Conversely, for a winter event, the home's temperature is likely to drop below the minimum value specified by the customer well before the end of the event. As a result, when the EHP turns back on after only 1-2 hours, the grid would still be within the period of the peak. Therefore, with current design parameters an electric heating DR event would have the impact of shifting the peak later but not meaningfully reducing it.

Examples of passive managed charging programs are time-of-use rates or specific incentive design programs that reward off-peak charging. For example, a passive program may offer incentives for charging between 8pm and 5am, but as the shift to a winter morning peak occurs, these passive program designs may need to shift to earlier in the evening to not conflict with higher winter peak coinciding with customers needing to drive out of their homes to get to work in the morning. This illustrates why program designs need to be developed in close concert with system demand shifts over time. Nevertheless, time-of-use rates may influence customer behavior over time which may ultimately enable more informed decisions between the EDCs and customers.

Active managed charging programs on the other hand provide utilities or a market aggregator working with charging networks, the tools to meaningfully impact locational demand – and therefore potentially ameliorate associated grid upgrades – subject to customer opt-outs. Active programs have the capability to directly control charging time, scale, and location, in order to achieve a variety of outcomes, such as managing peaks, absorbing excess renewable generation or supplying some ancillary services to a structured market. These programs rely on a reliable two-way flow of information that includes 1) a transport layer that relies on a communication signal via Wi-Fi, cellular, vehicle telematics, etc. to send the charging instructions and 2) a messaging protocol or standard that can help the device understand and execute the instructions.

Active and passive programs can work in concert with one another. Customers on time-of-use rates could opt into active programs to help them minimize their charging costs without them having to think about it. According to a 2021 report by NREL2 that cited DOE research, 80% of EV charging occurs at home due to the convenience and low cost of residential charging. That trend is expected to continue with increased EV adoption, thus elevating the importance of programs designed to manage home charging.

The potential for managed charging varies by sector and charge type.

Residential at-home charging: is the most promising current application, most customers plug in when they get home and remain plugged in overnight. This long dwell time means that there is a high amount of flexibility for changing when the charging happens. However, the activation of the charging must be done carefully to avoid creating a new local peak. For example, a residential program that prevents charging from 3pm-8pm but allows all vehicles to begin charging at full speed at 8pm would result in higher total system peaks than if each car had simply begun charging when it arrived home (See the modeling presented in Section 8.1.3). Furthermore, the optimal charge patterns on any given circuit are dependent on local system conditions (e.g., sub-regions with high PV on the system have entirely different load constraints than sub-regions with no distributed PV). The Company is working to address these issues with its program design.

Workplace charging: With the anticipated prevalence of home charging and hybrid work schedules continuing for a majority of customers, workplace charge management is expected to be applicable to, and of interest to, limited customer segments. Given the moderate dwell times and typically repeat users of such charging substations, there is some potential for managed charging at workplaces, especially as most workplaces will have demand rates with the EDCs and thus their own intrinsic desire to manage their charging. However, balancing the needs of the charging customer will be paramount. Customers must be assured they can reach a given level of charge by a certain time. Approaches will also have to be regionally specific depending on the amount of solar or other load on the system.

Public charging: This segment is not well-suited for load management programs due to the demand being inelastic. A driver who utilizes a charger at a highway rest stop, for example, does not have flexibility to change their charging behavior. One possibility for managing these loads is on-site batteries that can be charged and discharged in such a way as to flatten the overall load. The company expects these types of solutions to continue to develop over the next decade.

Fleet charging: While the residential market segment has the most managed EV charging engagement today, fleets have the potential to create the most local grid value in the future. The Company has begun early engagement with MHDV fleet operators looking to electrify. Appropriate charging of these fleets will be key to minimizing impact to both the grid and the customer's business operations. Thoughtful collaboration between the utility and fleet operators that considers existing routes, duty cycles, and load management potential when siting EV chargers can help to minimize upfront installation and ongoing operational costs.

Because MHDV electrification represents a potentially large increase in a customer's electric bill, it is anticipated that large fleet customers will have an interest in managing their demand. Customers who are already high consumers of energy will be familiar with the concept of demand management and may pursue EV EMS or load balancing software for fleets on their own. The incremental benefit that could be gained from layering a fleet managed charging program on top of charge management software that customers may install should be examined.

However, it is anticipated that electric demand management will be a new concept for many EV fleet customers used to managing costs associated with a different fuel resource (i.e., diesel). In the case of a small depot, their previous electric consumption may have only consisted of a small building and overhead parking light. Hence, the Company expects that a significant amount of education around EV charging optimization and overall demand management will be required for operators of newly electrified fleets.

Depending on the size and location of the fleet loads, it may make sense to work with customers on a case-by-case basis to develop a charge management solution that meets both the customer and local grid needs as opposed to a program that attempts to target fleets collectively. Vehicle-to-Everything (V2X) EVs of all types may be able to contribute to alleviating the peak if bidirectional charging capabilities continue to develop and appropriate contractual arrangements can be made with customers. This is a nascent industry, however, and the exact nature and magnitude of this potential remains unknown. Technology and safety protocols needed to support the successful delivery of such solutions at scale are still being developed. As of summer 2023, only a handful of chargers and EVs with bidirectional capability are approved for use in the United States. Current V2X functionality falls into three types discussed below.

Vehicle-to-Grid

V2G technology is an area of growing promise, especially as advancements in battery technology allow vehicle classes beyond light duty and school buses to electrify. For V2G to be a viable solution for providing system relief, standard bi-directional protocols and connectors must be developed in parallel. Strategic siting of MHDV fleets with V2G capability could allow that fleet to play a role similar to a large battery in alleviating grid constraints. However, vehicles are mobile assets, hence the value provided by V2G is difficult to quantify even where the capability is known to exist. Reliability of those V2G assets will vary based on fleet type and will be governed by business operations, which will determine how often those vehicles can actually be plugged in and discharge or charge when needed.

Vehicle-to-Home (V2H)

In V2H applications, a customer's EV is used locally to power a home or business rather than exporting energy to the grid. The ability for an EV to act similar to a battery system not only requires a compatible bidirectional charger and EV, but also special metering and equipment that allows for islanding. The extent to which customers pursue V2H as an alternative to a battery system for backup power during outage is unknown. However, such an application could potentially provide relief during times of high demand by serving local loads to prevent drawing power from the grid.

As a general challenge, the time that the system would most need the discharge is for the early-morning peak, which directly contradicts customer goals of having fully charged vehicles ready to commute to work. If remote work continues to be the norm for many industries, there may be customers who are willing to participate but it is simply an unknown at this time.

Vehicle-to-Load (V2L)

V2L technology does not require a bidirectional charger to operate. Vehicles with V2L have a built-in bidirectional charger and standard AC power outlets that can be used to power essential household appliances, such as refrigerators, lights and laptop computers. While several EVs currently offer V2L functionality, V2L is unlikely to play a significant role in demand mitigation as the household loads that can be supported are relatively small. V2L can, however, play an important role in limiting customer inconvenience and dissatisfaction associated with outages of minimal duration.

The Company continues to monitor developments in V2G and assess whether additional value can be created by developing programs specifically targeted to this as an asset class as opposed to treating the different types of V2X as either an EV or a battery.

9.1.3 Other Load Management Response Scenarios

Existing load management programs encourage customers to curtail load or discharge batteries during peak times on the ISO-NE grid. The timing of ISO-NE system peaks is largely coincident with when distribution constraints occur. However, programs that were designed to target load shed at the ISO-NE level only, cannot serve all of the use cases where load management could be beneficial to the distribution system at a more localized level. Certain locations on the system may experience constraints outside of the typical ISO-NE peak windows, and additionally, those constraints may not be purely due to load. The Company is exploring ways to make demand-side resources firmer through alternative regulatory constructs, asset types, and program designs that will allow for increased customer opportunities to provide localized system relief.

As described in Section 6, the Company will leverage its DERMS, AMI, and ADMS investments to test new ways to procure load flexibility services from DER customers and/or aggregators that can more dynamically respond to grid constraints in specific locations. As those technologies and the accompanying capabilities mature (i.e., increased data and energy usage visibility, short-term forecasting, improved grid management and control), the Company will learn which flexibility procurement approaches work best (i.e., programmatic vs. market-based) and scale those to most effectively address a growing set of grid needs in 2035-2050.

9.1.4 Battery Storage Charge Management

Front of the Meter (FTM) Batteries

Large, FTM battery storage solutions come in two versions.

a. **Standalone Storage** connected to the distribution system can be deployed for a variety of use cases, including to participate in the wholesale markets and/or state programs like Clean Peaks Standard, or to provide distribution grid services as NWAs. Depending on the intended use cases pursued, that energy storage resource may require more “headroom” on the distribution system, so that it can freely charge and discharge electricity from the grid at any time. Today, building that headroom to facilitate interconnection can require expensive upgrades to ensure that storage does not contribute to potential thermal overloads on the distribution system. To provide a lower cost and faster alternative to interconnection, as part of this Plan, the Company is scaling its flexible connections capabilities building from its ARI pilots. Flexible connections will allow small- and large-scale DER customers to reduce the grid headroom requirement by enabling the Company to actively limit storage operation based on real-time dynamic grid system conditions. DERMS, when implemented, will allow the Company to remotely monitor and operate storage.

b. **Co-sited with large solar storage solutions** aimed at reducing interconnection cost of solar sites by conducting peak shaving. These storage solutions absorb generation primarily from solar and discharge to the grid when no solar generation is available. In most cases, co-located storage never charges from the power grid, and depending on how the customer's system is designed, they may never discharge during peak solar generation. Solar and storage sites can be considered under NWA dispatch, as discussed in Section 9.3.

BTM Batteries

Many customers are pursuing battery storage to meet their own reliability needs, or to manage demand charges. Customers currently can participate in the Company's ConnectedSolutions DR program which provides incentive payments for participating in peak DR events called by the Company.

As noted above, current DR programs compensate customers for discharging the batteries at times coincident with the ISO-NE peak. In the future, more sophisticated dispatch strategies may be needed to help address localized grid constraints and help balance load and BTM generation on circuits. With AMI and DERMS fully implemented, the EDCs would be well positioned to use BTM DERs in their operational control, to manage demand on the grid more effectively. An aggregator that contractually commits to delivering the needed MW may also provide this support.

Regulatory rules for participation in both wholesale and distribution level programs will define the market. As battery storage system costs decline and their value to grid services develop, it is expected that electric customers' will more widely adopt batteries to meet their energy and resiliency needs and to provide services to the distribution system through a market mechanism. The Company will look to leverage this dispatchable BTM storage directly or through third parties to efficiently manage capacity.

9.2 Aggregate Substation Needs

There are network infrastructure projects needed beyond the 10-year planning horizon driven by electrification. Consistent with the ESMP planning process described in Section 6.4, the Company performed a review of projected substation transformer and feeder loading and identified capacity deficiencies which would detract from the distribution system's ability to support the Commonwealth's electrification goals in the 2035-2050 timeframe. High level solutions to address these deficiencies were developed, building upon the foundation established with the 10-year plans described in Section 6.

Due to the far-future nature of these capacity needs, the Company did not fully scope these investments and instead is providing an indicative summary detailing the number of major substation expansion or addition projects that it anticipates will be required in the 2035-2050 timeframe, based on this review. This is a preliminary view of the network reinforcement projects expected to be needed and is subject to change.

As part of its annual planning processes, and through each 5-year ESMP planning cycle, the Company will reassess and refine these plans in light of the latest available information, including the most recent forecast, localized loading trends (both through widespread electrification adoption and discrete electrification spot loads), DER adoption, and developing capabilities such as DERMS. All of these factors may result in modifications to the scope and scale of investments required to maintain pace with electrification adoption throughout the service territory.

The table below contains the aggregated investment needs between 2035-2050 to support the electrification forecast.

Exhibit 9.1: Aggregated Investment Needs from 2030 – 2050

Sub-Region	Number of Projects Needed – 2035-2050
Central	18
Merrimack Valley	13
North Shore	15
South Shore	16
Southeast	10
Western	14
Total	**86**

The following sections summarize major themes across the sub-regions.

Central

To support electrification load growth in the Central sub-region, the Company has identified a preliminary list of 18 projects for the 2035-2050 timeframe, including five new substations and six major substation expansion projects. Additionally, the Company will continue to build on the 10-year investments to convert the legacy Worcester backyards and High-Tension system to a distribution configuration more suited for modern needs. These distribution investments will enable the retirement of approximately nine 4.16 kV substations in the Worcester area.

Merrimack Valley

To support electrification load growth in the Merrimack Valley sub-region, the Company has identified a preliminary list of 13 projects for the 2035-2050 timeframe, including six new substations and six major substation expansion projects. Additionally, the Company will continue to build on the 10-year investments by extending transmission closer to the load centers of Chelmsford, Westford, North Lowell, Haverhill and Newburyport to relieve loading on the existing 23kV sub-transmission system.

North Shore

To support electrification load growth in the North Shore sub-region, the Company has identified a preliminary list of 15 projects for the 2035-2050 timeframe, including five new substations and nine major substation expansion projects. Additionally, the Company will continue to build on the 10-year investments by extending transmission closer to the load centers of Cape Ann area to relieve loading on the existing 23kV sub-transmission system, as well as radializing the existing Lynn secondary network system to be better suited to modern needs. These distribution investments will also enable the retirement of approximately seven 4.16 kV substations in this area

South Shore

To support electrification load growth in the South Shore sub-region, the Company has identified a preliminary list of 16 projects for the 2035-2050 timeframe, including five new substations and 11 major substation expansion projects. Additionally, the Company will continue to build on the 10-year investments by expanding existing single transformer stations to provide additional capacity, while increasing reliability and resiliency.

Southeast

To support electrification load growth in the Southeast sub-region, the Company has identified a preliminary list of ten projects for the 2035-2050 timeframe, including four new substations and three major substation expansion projects. Additionally, the Company will continue to build on the 10-year investments by extending transmission closer to the load centers of Attleboro, Foxboro and Wrentham, to relieve loading on the existing Union Loop 23kV sub-transmission system.

Western

To support electrification load growth in the Western sub-region, the Company has identified a preliminary list of 14 projects for the 2035-2050 timeframe, including one new substation and nine major substation expansion projects. Additionally, the Company will continue to build on the 10-year investments by extending the transmission closer to the load centers of North Adams, Great Barrington, Sheffield, and Northampton to support load growth and relieve the 23kv sub-transmission system.

9.3 Non-Wires Alternatives – Impact on Substation Deferral

In this section, the Company describes its approach to scale NWAs as an integral part of future network planning and operations.

As discussed in Section 6.4 and 6.11, the Company sees an important and growing role for NWAs to play as part of future network planning and operations. In particular, the Company plans to use its five-year and ten-year investment period to test and hone its NWA capabilities, as well as to stimulate the market among flexibility service providers in MA, so that NWAs can be delivered reliably and cost-effectively at scale in the 2035-2050 period. This includes using the 2025-2034 period to develop the technology, regulatory frameworks, customer programs, rate design, and procurement mechanisms to scale existing NWA enabling efforts underway.

System-wide peak load reductions

As described in Chapter 5, the Company's load forecast, which the planning teams rely on to evaluate the need for distribution network infrastructure investments, reflects the peak load reductions from various technologies and programs such as EE, DR, and solar PV. Without these subtractors, the system peak in all sub-regions would be significantly higher and would require that the Company implement sooner and more significant network infrastructure investments. These programs function as "system-wide" NWAs and are considered by the Company through its forecast and the adjustments made to the forecast.

1. **EE, DR, and EV managed charging programs**

   As noted in Chapters 4 and Chapter 6, the Company's network is supported by nation-leading Mass Save EE and DR programs which have helped to offset peak load growth and reduced the need to expand network infrastructure considerably over the last decade. The Company also administers an EV off-peak charging rebate program, which helps to shift EV charging load outside of peak hours.

   In the 2035-2050 timeframe, the Company intends to scale and evolve these system-wide programs as both electric network and customer needs change and continue to leverage them to offset peak load growth and defer traditional wires-based network investment.

2. **Time-varying rates (TVR)**

   As described in Section 6.11, the Company also plans to begin testing and offering TVR in a phased approach within the immediate five-year investment period alongside AMI deployment. In the 2035-2050 timeframe the Company will have already achieved widescale deployment of both AMI and TVR and expects increased participation in TVR. In 2035 and beyond, customers will have the technological infrastructure, access to data, and ability to seamlessly interact with the Company and other third parties to have choice and control in how they want to support smart use of the grid, pursue electrification, and reduce the overall costs of the energy transition. As more customers adopt TVR, the forecast will adjust to reflect the peak load reduction benefits across the network from TVR, which will help reduce and/or defer the need to deploy network infrastructure across the network.

Targeted NWAs

Chapter 6 includes the Company's proposal to buildout necessary technology enablers such as DERMs, ADMS, AMI and associated data and security investments (Section 6.3), as well as customer-facing programs (Section 6.11) to test how to best procure flexibility to meet the grid need in a specific location. The Company intends to develop and test the best ways to communicate with, monitor, control, dispatch, compensate, and procure flexible resources on the distribution network. The Company will leverage a "test" and "scale" approach to learn quickly and maximize the potential of these NWAs to transform the way the Company operates and plans the network.

In the 2035-2050 timeframe, the Company envisions reaching a certain level of maturity for its NWA capabilities based on the learnings gathered over the preceding five and ten-year investment periods. In this future timeframe the Company expects to have identified and scaled key best practices, as well as transformed the network planning and operations processes to more fluidly embed NWAs as agile solutions that can be used to meet a variety of grid needs across different locations. This of course will be dependent on the learnings gathered over the next several years, though there inevitably is an important growing role to leverage NWAs tactically to offer more affordable and reliable options for Company customers, where possible.

9.4 System Optimization – Impacts on Electrification Demand

Investment in digital, data and IT systems from 2025-2034 including DERMS, AMI, ADMS, ARI, and communications infrastructure will allow the Company to more actively and flexibly manage load and supply and deliver improved electric network system optimization for all Company customers. The Company will continue to leverage those foundational investments to evolve system optimization programs during the 2035-2050 period.

9.5 Alternative Cost-Allocation and Financing Scenarios – Impact on Investments

See Section 7.1.2. In addition, the Company will pursue future alternative financing opportunities that may emerge circa 2035 and beyond (e.g., from new federal legislation).

9.5.1 CIP 2.0 (Solar) Projects and Cost Allocation

See Section 7.1.2.

9.5.2 CIP 3.0 (Battery Storage) Projects and Cost Allocation

See Section 7.1.2.

9.6 Enabling the Just Transition Through Policy, Technology, and Infrastructure Innovation

The Company is committed to delivering a clean, equitable, and affordable energy future for all our customers. In addition to ensuring that the customers and communities served have equitable access to safe and reliable energy services, the Company is also committed to ensuring the technology and environmental benefits the clean energy transition will bring are felt by all. These principles are articulated in the Company's mission, the Responsible Business Charter,[4] and the Draft Equity and Environmental Justice Objectives for the Company's Massachusetts Distribution Business.[5]

As the Company works to advance a clean energy transition that centers equity and environmental justice in collaboration with regulators and stakeholders, two key tenets of equity will be focused on:

- **Procedural equity** to ensure that stakeholders and communities impacted by energy projects and programs have the necessary information and opportunity to engage in and inform project siting, development and implementation and program structures and outcomes.
- **Distributional equity** to ensure that the clean energy transition supports the more equitable distribution of the benefits and burdens associated with the clean energy transition.

For example, today, customers that are deemed income-eligible to participate in energy assistance or targeted energy efficiency programs are challenged by a lack of available and accessible information, hurdles to enrollment, and inequitable distribution of available assistance, impacting both procedural and distributional equity. Some of these challenges can be addressed through changes to tariffs and regulation while others will require legislative policy changes. The Company is taking steps today to understand and advance necessary changes to make these programs more equitable and effective, including in near-term filings at the DPU, and working with impacted stakeholders and others to inform these efforts.

As the Company continues to develop future programs that ensure all customers are equitably served, it is committed to integrating this focus across the business by:

- Increasing transparency and education about future infrastructure investment plans, including the need for investments and the benefits and impacts to a host community;
- Engaging early with stakeholders, including directly and via trusted community sources, and enhancing open communication that supports clear and timely information sharing, community feedback, and ongoing dialogue;
- Expanding our understanding of community concerns and priorities;
- Enhancing project and program outcomes by identifying opportunities to mitigate adverse impacts and support community and customer benefits;
- Reducing barriers to participation in customer programs that can benefit low-income customers and environmental justice populations;
- Partnering with our communities and local organizations in support of broader social, economic, and environmental progress;
- Directly supporting economic opportunity and advancement, including through the development of a local, diverse clean energy workforce and supply chain; and
- Monitoring and informing on our progress in supporting equity and environmental justice on a regular and transparent basis.

[4] https://www.nationalgrid.com/document/134426/download
[5] Draft Equity and Environmental Justice Objectives for National Grid's Massachusetts Distribution Business

Additionally, the Company is committed to working in partnership identifying and aligning around community benefits associated with clean energy infrastructure projects and innovative ways to create agency. Massachusetts has precedent for this, for example, through vehicles such as The Community Preservation Act, which provides local communities the opportunity to collect and direct funding to community priorities, including open space protection and affordable housing. The Company looks forward to working with GMAC's newly established Equity Working Group to better identify and define opportunities to address policy, technology, infrastructure and program inequities as this Plan evolves and is implemented over time.

9.6.1 Aggregation of All Clean Technology Incentives (in Respective Scenarios) Focused on EJ Communities

The Company recognizes that people in EJCs, including low- and moderate- income (LMI) customers, face barriers to participation in programs designed to help customers manage their bills or participate in the clean energy transition. In April 2022, the Company's Customer organization realigned to address the complexity of various customer segments, including LMI customers, with a vision and plan to create an organization focused on the performance of segments by having a deep, holistic understanding of LMI customers.

A comprehensive assessment was conducted with the following goals:

- Gain a deep understanding of the LMI customer segment
- Identify gaps within product offerings
- Apply key outcomes of an extensive ethnography study conducted in partnership with E-Source, and
- Coalesce work in-progress impacting LMI customers from across the company

This effort identified gaps within the digital product space presenting barriers to the engagement of customers and program uptake, the need for more targeted and consistent outreach and marketing, and opportunities to better utilize and align existing data, efforts, and programs.

The Company is addressing these gaps and opportunities through a holistic strategy that focuses on:

- Establishing and expanding partnerships, both internal and external
- Centralizing marketing to better align communications and outreach about products, programs and services and target these efforts
- Identifying ways to best structure and package, where possible, products and solutions
- Expanding education and outreach, including the work of the Company's Customer Advocate team and in-person Customer Energy Savings events, which are jointly hosted with local governments, community organizations and other trusted partners.

The Company will continue to incorporate additional outreach and support to EJCs in its clean energy program design and in its community and customer outreach and engagement, including as it has done in its EE and EV programs to date, and work with others to continue to evolve our strategy, programs and offerings to better meet the needs of EJC and LMI customers.

9.6.2 Discussion of Potential to Use Incentives and Dis-incentives to Align with Distribution Upgrades

As discussed in Sections 6.11 and 9.3, the Company plans to deploy several incentive programs and mechanisms to shift load away from peak times to:

- Help reduce or defer the need for distribution network upgrades, and
- Reduce the costs and risks of managing overloads to distribution equipment in instances when the load growth may exceed equipment rating prior to the in-service date for distribution network upgrades.

These include both system-wide methods such as TVR, EE, DR, and off-peak managed EV charging, as well as targeted methods involving NWAs to address specific distributed network needs.

Consistent with the discussion in Section 9.3, in the 2035-2050 timeframe the Company expects to scale these programs in future years across the network to maximize their benefits to customers.

9.6.3 Potential Incentive Allocation Movement Among Clean Technologies Ultimately Flowing to EJ Communities

The Company recognizes that people in EJCs face barriers to participation in programs designed to help customers manage their bills or participate in the clean energy transition. Per Section 9.6.1, above, the Company has a holistic strategy to identify, engage and provide clean energy products and solutions to EJCs, including through ongoing EE and EV program efforts. The Company will continue to incorporate additional outreach and support to EJCs in its clean energy program design and in its community and customer outreach and engagement, working with affected and representative stakeholders, including the newly formed GMAC Equity Working Group.

The company has also identified several programs in this Future Grid Plan that are that are either inflight and/or will be submitted to the DPU for consideration, including the Resilient Neighborhoods program discussed in Section 6, which is designed to improve climate adaptation and resiliency for communities via the deployment of solar located on Company property. The Company is currently working with potential community hosts to identify benefits that can be leveraged from the solar, including creating resiliency hubs and EV charging support, thereby aligning and leveraging program funding and incentives being used for one technology to support other efforts.

9.7 New Technology Platforms

The Company proposes to build on its currently in place and in-progress technology platforms, including those approved in the first and second ESMP periods, with further investments to support delivery of the 2035- 2050 ESMP objectives.

Consistent with the framework in Sections 4 and 6, below the following technology investments categories are described:

1. **Network management and communications** includes technologies that the Company uses to communicate with, monitor and control assets on the network and to manage and respond to grid outages and abnormal system conditions.
2. **Metering and billing systems** include technologies that the Company uses to measure customer energy usage on the grid and issue accurate bills based on those meter reads.
3. **Customer portals** include the customer-facing and internal systems that the Company uses to leverage today to manage customer programs such as those related to EE, EVs, and new customer interconnections.
4. **Data** includes the type of data that the network planning and operations, and customers have access to, as well as the Company's ability to manage, integrate, and operationalize that data to transform how the Company operates and plans the grid.
5. **Asset planning, management, and work execution** includes the systems that the Company uses to support grid planning and design, construction and capital deployment, and regular system maintenance and field operations.
6. **Security** includes measures in place to ensure the security of the Company's technology systems from potential cyber threats and attacks.

The Company expects to focus on the six key areas identified above in the 2035-2050 period to advance the digital transformation of the utility:

Network management and communications

A foundation of the Company's modernization plan is the development of a granular and real-time model or "digital twin" of the Company's electric transmission and distribution network. This model also features real-time control of network assets, including predictive and automated schemes to reconfigure the system for various purposes, including customer reliability, efficiency, and the prioritization of clean energy use. The end-state of this transformation will be characterized by shorter and less frequent outages, higher quality power, and the integration of clean energy. To avoid outages in the future, this self-healing system will be able to isolate portions of the grid and leverage a variety of sources of energy, including DER to create microgrids within the larger electric grid based on real-time conditions.

To enable this future state, the deployment of sensors, controls, and real-time communications throughout the network will need to be enhanced to make the bidirectional data collection and control from the field to the operating center and back again instantaneous, with data transmission, interpretation, strategy, and control schemes deployed at the sub-second timeframe.

To enable the collection, interpretation, and transmission of data across the network, the Company will enhance the capabilities of the localized Field Area Networks (FAN) and Wide Area Networks (WAN) that facilitate data management on the massive scale required for the incorporation of data from the grid edge like smart meters and grid-supporting DER. Dozens of systems, monitoring, controlling, and coordinating thousands assets will need to be conducted faster, more reliably, and with minimal human intervention.

Metering and billing systems

The future of metering and billing systems are tightly coupled with the broader trends of digitization, consumer empowerment, and the integration of renewable energy and DER. As the grid continues to evolve, these systems will reflect these changes, offering more granularity, transparency, and adaptability to operators and customers alike. In the future, the advanced customer meter will be the gateway for customer empowerment as an active participant in the energy system.

With the deployment of AMI – embodied by the new generation of smart meters, the utility activates the ability to facilitate two-way communication between the meter, operating center, and end-customer. This not only allows for real-time consumption tracking, but also a variety of other OT use cases such as remote connect/disconnect to significantly improve the move-in/move-out process for customers and the better integration of DER. Advanced features and programs will enable customers' DERs to participate in the energy marketplace in a way not possible with today's meters. (e.g., transactive energy programs where customers can change the energy services that they're paid to provide through their DER in real-time.) A good example would be the Company sending an optional incentive offering to a customer's phone to provide voltage support in a targeted location on the grid in real-time.

An enhanced billing and payment process will also provide considerable experience improvements for customers to receive, review, and pay their energy bills or credits in an environment that meets evolving customer needs and expectations. The most common interaction that customers have with their utility is around their monthly bill, and with the introduction of variable rates and transactive energy markets, the number of customer questions associated with this change will increase significantly. The Company's new billing and payment portal will offer customers targeted information that will reduce the need for them to call in to speak to a Customer Service Representative by providing detailed information about Company rates, as well as access to a suite of actions that they can take to dig deeper into their consumption data details or take action to reduce their costs in the future.

These AMI meters also function as grid edge sensors for the purpose of network management and will offer the utility valuable insight about conditions at the grid edge in real-time. This enables a whole new set of use-cases, including last-gasp and advanced outage management functionality, whereby the utility can identify which AMI meters are no longer connected to the utility network, thereby creating a model of where a distribution network fault may have occurred so the OMS can reconfigure the network to minimize or prevent outages for customers via microgrid enablement and dispatch trouble crews to the estimated location of the fault to restore power to the remaining customers impacted by the outage.

Customer portals

The Company will continue to enable a variety of new, automated processes with enhanced customer experiences as data is processed and communicated more quickly via customer portals. These portals will empower the customer to make more active decisions around their energy and enact those changes in real-time. As the Company offers more opportunities for customers to control their energy costs, consumption, self-production, and other choices, the Company will aim to offer an intuitive user experience with seamless designs, easy-to-navigate interfaces and customization features that will make it easy for customers to complete the required tasks.

Customers will not only need an easy, efficient, and engaging way to review that data, but will also expect the Company to make recommendations and digital products to make it easy for them to take further action on their energy goals. The deployment of AMI will enable customers to access exponentially more data about their account, energy consumption, and load profile. The future billing portal will provide a customer-centric web platform that will enable customers to review this data, receive recommendations on how they can achieve their energy goals, economic models of the impact of those measures, and allow them to securely provide that data to third party vendors that can make the process of acting even easier.

Enhanced customer portals will also significantly improve the experience of customers who choose to pursue and monetize DER. In the early phases of their DER journey, customers will be able to efficiently access and review their energy consumption data and understand if solar, energy storage, or other DER-actions are best for them. They can then seamlessly and securely provide data that is critical for project design and development to third party vendors. Vendors will be provided a package of data on the customer, their energy consumption, location on the grid, and expected process for interconnection to significantly reduce the time and soft cost associated with project development.

Data

Real-time data collection, transmission, and analytical processes will enable the Company to make informed strategic and operational choices, analyzing vast amounts of data from equipment, sensors, and customer behavior. This will enable the Company to make accurate predictions and optimize resource allocation: In short, the Company will leverage real-time data and analytics to do less with more.

The Company will leverage machine learning and advanced analytics to transform a variety of processes and capabilities, (e.g., predictive maintenance, load forecasting, customer service, security, DER integration). The Company currently collects and has access to more data than can be reliably processed with today's technology. However, evolving technologies will create new use cases – making the process of leveraging this data faster, more reliable, and cost effective.

As machine learning capabilities evolve, the Company will continue to train models to be able to analyze performance anomalies and operational characteristics of assets to mitigate asset failures before they occur. For example, modeling and extrapolation of vibration sensor data at a substation could simulate when an equipment failure might occur so asset management teams can prioritize the exact time to send a maintenance crew.

The Company will also leverage advanced data analytics and modeling to create new rate structures and incentives that not only solve today's load management challenges, but also prevent future issues based on inputs from the Company's systems and third-party data. This could include analyzing EV sales, real estate or permitting data to project load impacts on the grid and take mitigating action prior to significant load changes that could require costly infrastructure upgrades.

The future data system will ensure the Company has accurate, timely data that can be used for short and long-term analysis of network operations and health, energy supply and demand, weather and climate impacts, and customer preferences, to enable us to address issues quickly, conduct predictive maintenance, extend the lifespan of critical components, integrate more renewables, tailor products to Company customer needs, and operate the grid more efficiently and effectively.

Robust data security and encryption will be essential to protect customer and network data, comply with all regulatory requirements, and with suitable protections in place, allow for third party sharing. Data will be the backbone of the Company's digital transformation and will help pave the way to a more sustainable and resilient energy system.

Asset planning, management, and work execution

A key focus of the Company's strategy to minimize the frequency and duration of outages while keeping costs low is the optimization of asset management and work execution. As climate change poses new risks and challenges to maintaining the distribution network and assets, digital products and data will be increasingly relied upon to understand and predict asset conditions.

Asset management teams are deploying advanced sensors – embedded in field equipment like transformers to provide real-time data on performance and conditions like heat to facilitate early detection of problems and optimizing usage of the asset. As noted above, the Company's asset management teams can then leverage machine learning to predict when assets are likely to fail or need maintenance. This proactive approach minimizes downtime, reduces costs, and extends asset lifespans.

When visual inspections need to be conducted, the Company and affiliated vendors will increasingly rely on drone or robot-assisted inspection techniques to collect detailed visual asset data, reduce costs, and enhance safety at the inspection site. Unmanned Aerial System (UAS) and other remote-controlled systems can access challenging and hazardous locations, such as above high-voltage transmission lines and close to dangerous or damaged equipment, collect high quality data such as photogrammetry, infrared imagery, and LiDAR to inspect both utility assets and the environmental risks that surround them.

Integrating this asset data, analytics, and machine learning with an enhanced work management tool will enable the Company to balance priorities of reliability, sustainability, and affordability during periods of notable change in the industry and the Commonwealth. Pairing enhanced asset and workforce management solutions, the Company's teams will accomplish enhanced resilience, reliability, and affordability.

Security

Robust cybersecurity measures ensure the Company safeguards critical infrastructure, protect customer data, and ensure uninterrupted operations in the face of evolving cyber threats. Internet of Things (IoT) devices in smart grid applications, and an increased use of digital systems, data communication, and smart grid technologies presents new entry points for cyber attackers. Data from these devices will be critical for optimizing grid performance and making informed decisions.

The Company will employ continuous monitoring and threat detection mechanisms, intrusion detection systems and security analytics, and comprehensive incident response and recovery plans. Machine learning algorithms can detect unusual patterns of behavior and trigger appropriate responses to mitigate cybersecurity risks. It will be critical that the Company communicates and engages with other utility and industry partners to collaborate and share information about cybersecurity threats and best practices. Building a collective knowledge base will enable the industry to proactively address emerging threats and develop more effective cybersecurity strategies. In 2035 – 2050 cybersecurity will require significant investment across all digital and business initiatives to ensure a safe, secure, and reliable network remains in place for all customers.

Section 10

Reliable and Resilient Distribution System

This section articulates the importance of reliability and resiliency, and describes the Company's programs and investments to ensure its system is prepared for future climate hazards.

Key Take-Aways

- The Company has a strong track record of building and maintaining a resilient system that has adapted to meet evolving challenges and threats. Increased electrification means that every facet of people's lives and the state's economy will be dependent upon the resiliency and reliability of the network.
- Residents of the Commonwealth have already begun to experience the effects of climate change. The Company is constantly monitoring and adapting to climate-related threats posed to the electrical network. The most pertinent identified threats are coastal flooding, temperature extremes (both high and low), extreme winds, and wildfire. Resiliency measures (largely driven by engineering tactics and construction design standards) are in place to combat these threats.
- All resiliency investments are considered critical to the continued safe and reliable operation of the electrical network. As such, relevant investments are defined to be part of the Company's "core" plan, and funding will be requested in the forthcoming distribution rate case.

10.0 Reliable and Resilient Distribution System

The Company undertakes careful planning to ensure reliable and resilient network standards. This is becoming **ever more important in an increasingly electrified world.**

This section will:

- Define and highlight the need for grid resiliency and provide review of the Commonwealth's Climate Assessment, and Hazard Mitigation and Climate Adaptation Plans.
- Review many of the distribution reliability and resiliency programs managed by the Company and how these are expected to adapt and evolve within a continuously changing climate.
- Assess the grid's vulnerability with respect to expected climate hazards.

10.1 Review of the Commonwealth's Climate Assessment, and Hazard Mitigation and Climate Adaptation Plans

The 2022 Climate Act specified that the Plan includes and describes 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 increased electrification of the Commonwealth will bring new expectations for a reliable and resilient network as customers rely on the Company's networks for vehicle charging and, heating in addition to the way that they use electricity now.

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. This reliance and necessary grid resilience is only expected to increase through the pursuit of the Commonwealth's electrification goals, and the increased adoption of EVs and electric heating.

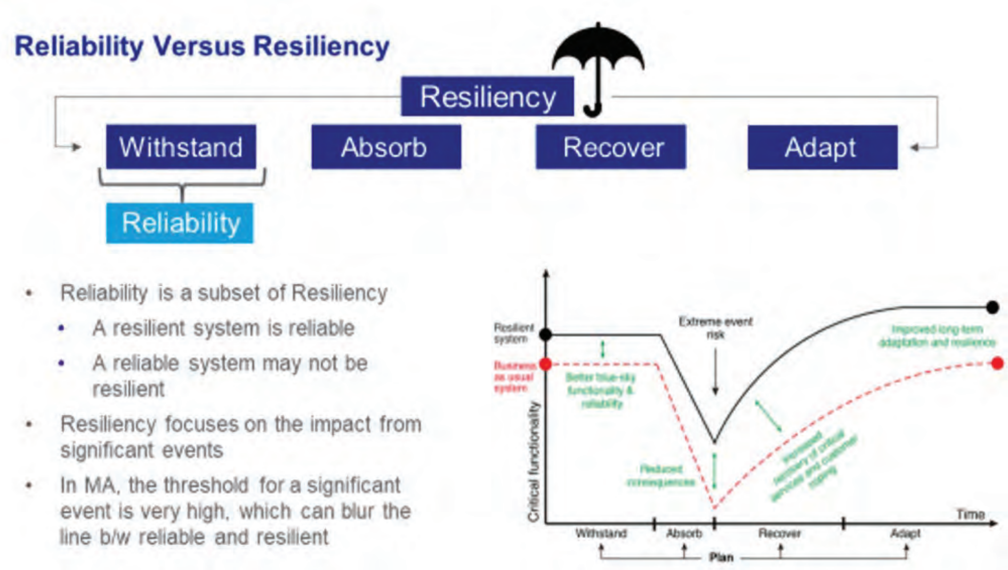
Prior to discussing the Company's detailed plans below, there first must be alignment on the definitions of Resilience and Reliability.

Traditional utility approaches to reliability focus on upholding performance according to regulatory reporting criteria. This excludes the impacts from major events which cause outages that are statistically outside the norm for the system. This includes:

- An event which results in a state of emergency being declared by the Governor
- Any unplanned event interrupting 15% or more of customers
- An event that was a result of failure of another Company's transmission or power supply system
- Single day minutes of SAIDI exceeding 4β method (2023 thresholds - MECo: 25.214 minutes, NANCo: 161.438 minutes)

Resiliency can broadly be defined as the ability of the distribution system to withstand and recover from disturbances, including major events. It is expected that the Company's service territory will be experiencing more common and more severe storm events. Although these are excluded from traditional reliability analyses, the Company will nevertheless consider the impacts of these events as part of its system resilience and reliability planning.

Exhibit 10.1 – System Resiliency vs. Reliability



Many factors contribute to and impact the distribution system resiliency and reliability. For example, the system can be designed and constructed to withstand increasing risks (i.e., “hardening” the system), or certain emergency response and operational activities are employed during and immediately after an event that causes electric service disruption. At the Company, specific areas in which system resiliency/hardening is a focus are:

- The regular updates to construction and equipment standards applied to distribution infrastructure projects.
- The Company’s vegetation management programs.
- Asset Management practices and the distribution system planning studies to identify existing and project future system performance concerns and the infrastructure development required to address the concerns identified.
- The consideration of both reactive and proactive infrastructure development programs that adopt new and/or replace/modify existing assets.
- The development, continued refinement, training, and execution of the Company’s Emergency Response Plan (ERP).
- Tracking the latest developments in climate science and the trajectory of climate change within the service territory

The Company has developed robust processes in each of these areas which allow the Company the ability to respond both proactively and reactively as the impacts of climate change on distribution system performance are realized. The Company recognizes that the threat of climate change is significant and it cannot be resolved through isolated or short-term initiatives. Accordingly, preparing for and responding to climate change is embedded in the way the Company plans, constructs, and operates its system as a normal course of business. Specific ongoing and completed resiliency and hardening measures are discussed within this document as examples of ways that the Company’s response to climate challenges have materialized. As the understanding of the magnitude, scope, and breadth of climate-related challenges matures, the flexibility and robustness of the Company’s processes will allow additional measures to be developed and implemented.

10.2 Distribution reliability programs

10.2.1 Distribution construction standards

The Company regularly reviews and updates its distribution construction standards. The prompts for reviews are wide ranging and include items such as assessing continued availability of specific equipment, requests from internal departments of the Company (e.g., the Construction and Maintenance department), revisions to regulations that impact the Company's operations, and new technology adoption. Changes in construction standards stemming from environmental change are not new and the Company has implemented a significant number of improvements over the years that have now become standard practice.

Over the past several years, the Company's distribution standards have been reviewed and modified with a specific focus on changes that will advance system storm hardening and resiliency. These changes are designed to improve distribution performance during extreme weather events in several distinct ways including:

(i) reducing the number of customers experiencing outages;
(ii) reducing the duration of outages when they are experienced by customers; and
(iii) mitigating the impact to customers during distribution system outages.

As a result of its review, the Company added a Storm Hardening section to its Distribution Construction Standards in 2014.

The Storm Hardening section is unique in that it describes and explains the Company's approach to improving the distribution system's resilience through storm hardening, with specific updates to the standards then embedded in other sections. The Storm Hardening Standards discussed in this section of the Distribution Construction Standards are one part of the Company's comprehensive approach to resiliency. They primarily focus on making distribution system components more resilient electrically and structurally. These changes are intended to be part of all routine construction going forward, not just for use in targeted storm hardening of feeders (i.e., distribution circuits). Near-term considerations for resilience focus on system operation and restoration after a major event. Long-term considerations focus on infrastructure improvements that must be done before a major event – including aspects of grid operation, vegetation management, electrical and structural strength, and robustness of distribution system components. Resilience considers all hazards and events, including high-impact low-probability events that are commonly excluded from reliability reporting.

During extreme weather events, most damage to the overhead distribution system is caused by falling limbs and trees. The approaches put into practice by the Distribution Construction Standards attempt to reduce electrical outages or structural damage caused by trees and limbs. In particular, the standards are aimed at limiting the number of customers affected by tree and limb related outages and limiting the duration of those outages by allowing partial restoration of feeders and allowing quicker restoration of damaged lines. Storm hardening standards will be applied to all new or replaced structures in critical locations, coastal areas, and locations at risk of cascading failures (e.g., chain-reaction of equipment failures). Storm hardening is implemented in the following areas:

- Critical structures hardening
- Cascading prevention
- Coastline area targeted hardening
- Existing lines hardening

The Company's review of construction standards prompted by the impacts of climate change will continue. The Company is participating in ongoing research work at the Electric Power Research Institute (EPRI) on distribution grid resiliency. This work has included research into the response of overhead distribution lines to impacts from falling trees and limbs. The preliminary results from the

EPRI work have brought about changes to the Company's Distribution Construction Standards, with a focus on reducing the number of customers affected by major storms through selective strengthening of structures and conductors at critical locations like tie points between feeders, automated switching points, and the multiple circuit lines. Early study results have also driven changes to the Company's standards that are focused on the reduction of the duration of outages through the strengthening of manual switching structures, and the use of periodic dead-end structures to prevent cascading failures.

The Company continues to participate in ongoing work at EPRI focused on how individual components fail in a line hit by falling trees and limbs. The goal of this work is to find ways to make lines fail in ways that are more easily and quickly restored. For example, the study is evaluating the potential benefits of using sacrificial components at sensitive locations like dead end structures. As useful and practical results from this work become available, the Company will make further modifications and additions to its construction standards.

Exhibit 10.2 – Breakaway Connectors

In addition to continued consideration of developing technologies which can be applied to promote distribution resiliency, the Company is in the process of examining its Distribution Construction Standards through the ongoing climate vulnerability assessment work which is projecting the impacts of climate change to its system (Section 10.4).

10.2.2 Vegetation Management Programs

The Company's Cycle Pruning Program is designed to keep vegetation a safe distance from the power lines. When vegetation grows into power lines, it can cause service interruptions, pose a potential public safety hazard, and in some cases, start a fire. Maintaining clearance between vegetation and the power lines helps mitigate these risks and allows the Company to restore power more safely and efficiently during a weather event.

The Company has a dedicated Vegetation Strategy team which is responsible for developing long-term strategy, planning, budgeting, and delivering the annual work plan to ensure safe and reliable service for Company customers. The Company continues to adapt its Vegetation Management Program to address the latest research, to meet regulatory and financial targets, and achieve high levels of customer reliability so that the Company's program reflects best practices and results in the creation of an industry best-in-class program. Using the SAFe as described in Section 6.3.1, the Company is also deploying new digital products to support its vegetation strategy.

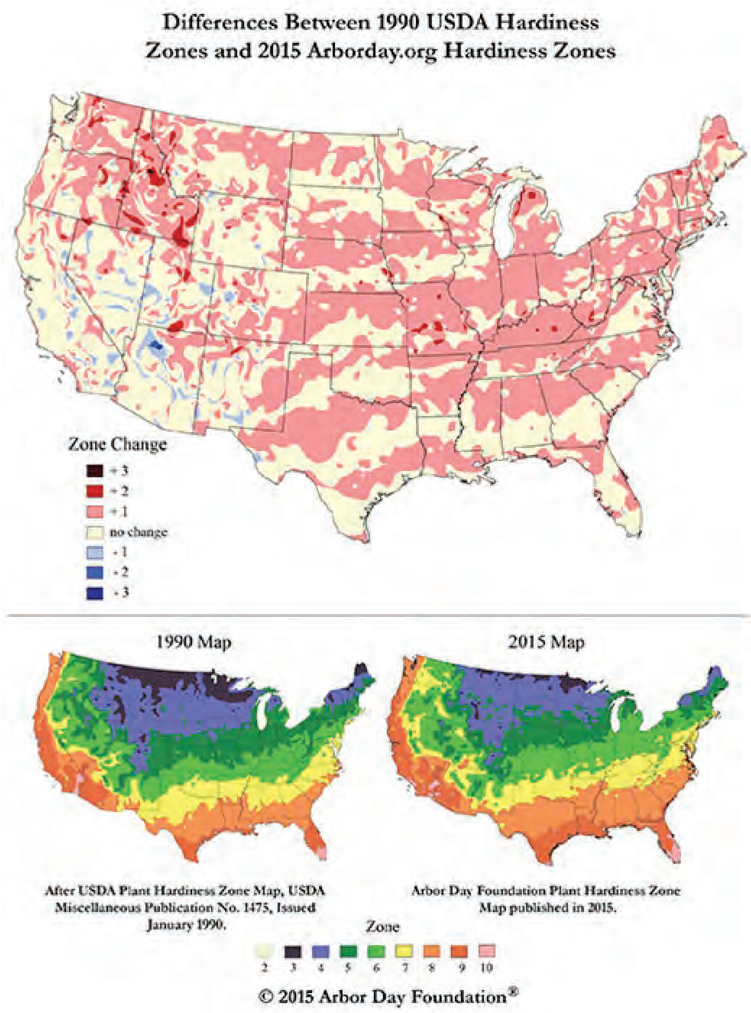
The impacts of climate change will create a significant challenge in meeting the program's goals for many years to come. With an estimated stocking density of 208 trees per mile, the Company's electric system across the State is vulnerable to harsh conditions during major weather events, which are becoming both more common and more severe due to climate change. These events can cause substantial damage to the system and cause interruptions that can last for multiple days.

Exhibit 10.3 – Weather-Related Tree Contact

The impacts of climate change are already noticeable on the Company's system. The Company's assessment is that over time, a fixed cycle-based approach will no longer be sufficient to prevent vegetation from growing into the power lines. As illustrated in Exhibit 10.4, a significant portion of the State has changed from hardiness zone 5 in 1990, to zone 6 in 2015. This means that temperatures are rising, which will increase vegetation growth rates.

With higher average annual temperatures and longer growing seasons, an increase of vegetation growth into conductors will occur in between pruning cycles. This creates a public safety hazard, makes routine maintenance both more dangerous and more expensive, and increases restoration times during storms. To help address this climate change impact, the Company has transitioned to a condition-based planning approach to determine when and where pruning should occur on its entire distribution system.

Exhibit 10.4 – Difference Between 1990 and 2015 USDA Hardiness Zones



In response to these trends, over the previous five years, the Company has spent approximately $142 million on maintenance pruning, Enhanced Hazard Tree Mitigation (EHTM), and Enhanced Vegetation Management (EVM) to protect its electric distribution system and ensure safe and reliable service for the Company's customers in the Commonwealth. As the Company continues to build more infrastructure to meet the needs of Company customers, it will be essential to increase the vegetation management budget proportionally to maintain that infrastructure in the future.

The Company's EHTM program seeks to identify and remove hazard trees, which are diseased or dying trees, which could potentially impact the electric system on both blue-sky days and during weather events. The EHTM program provides a significant reliability benefit to the Company's customers across the State. Since its inception, the Company's EHTM program has averaged a 19% reduction in tree-related events, a 39% reduction in customers interrupted, and a 32% reduction in customer minutes interrupted on circuits to which it was applied the year following EHTM, compared to a three-year average prior to EHTM.

The Company's EHTM program is designed to be flexible to evolve to address constantly changing issues which affect vegetation throughout the State, such as extreme drought and invasive species, both of which reduce tree strength and increase the risk of outages. While these issues may or may not be tied to climate change, they are resulting in large numbers of dead or dying trees which will impact the electric system during weather events.

In addition to these core programs, the Company also began implementing the EVM as a pilot program in Massachusetts in 2019. It targets worst-performing circuits which have experienced large numbers of tree-related outages and serves critical infrastructure. The pilot seeks to achieve greater clearance between vegetation and power lines. In some areas ground-to-sky clearing will be implemented, meaning there will be no vegetation growing over the wires. The pilot program also takes a similar approach as the EHTM program and removes large numbers of hazard trees. With these measures demonstrated, the Company's distribution system will be more resilient during major events. The EVM Pilot has averaged a 39% reduction in tree-related events, a 47% reduction in customers interrupted, and a 44% reduction in customer minutes interrupted after work was completed.

10.2.3 Asset Management Practices and Distribution System Planning

Asset management is the coordinated capability to make lifecycle cost, risk, and performance decisions and thereby create value for an organization and its customers from its assets. Engineering is the capability to design, build, and implement practical solutions to complex problems and requirements across multiple disciplines. At the Company, asset management and engineering are vital to delivering safe, efficient, reliable, and environmentally sound performance in each of its lines of business.

Embedded within the Company's asset management practices are the processes followed by distribution system planners in the execution of long-range distribution system planning studies. System performance assessments executed within these studies include a focus on system voltage, capacity, asset condition, and reliability. A completed analysis applies the Distribution Engineering Planning Criteria (which details acceptable performance) in the identification of existing and projected system performance concerns. A completed study includes recommendations for infrastructure development projects that will address all concerns identified.

The planning process and its performance assessments are fundamental and robust enough to identify trends in system performance degradation that might stem from the environmental impact of climate change without necessarily making the connection to climate change as the root cause and make recommendations that mitigate the impact of the root cause. An example provided in Section 10.2.1 is the Company's adoption of tree wire and spacer cable systems in its construction standards as a direct result of analysis done by distribution system planners. As the Company enhances its overall asset management capabilities and the subset distribution system planning processes, it will result in continuous improvement in system hardening and resiliency.

10.2.4 Infrastructure Development Programs

Infrastructure development programs are an approach designed to address the addition, replacement, and/or modification of specific assets that are in service or determined necessary to be placed in service across wide portions of the service territory. The prompts for program development or modification are varied and include items such as asset condition, operational safety, and service reliability. With the execution of most programs, the distribution system becomes more resilient/hardened to the impacts of climate change. Specific programs that have and/or are being executed with system resiliency/hardening being a significant benefit include the following:

Recloser installations

Line reclosers are devices that detect and interrupt fault current and, after a prescribed time delay, reenergize the line. As of the writing of this Future Grid Plan, the Company has installed approximately 1,900 560/800A[1] reclosers across the State over the course of several decades. Reclosers contribute to distribution system resiliency by reducing the frequency of permanent interruptions resulting from system faults that are temporary in nature. In addition, reclosers significantly limit outage exposure when they operate to clear permanent faults, since customers ahead of the line recloser installation will not experience an outage. Fault Location, Isolation, and Service Restoration (FLISR) is a program within the Company's Grid Modernization Plan and is described further in Section 6. It utilizes line reclosers and intelligent programing to isolate faults and immediately restore service to customers in unimpacted sections. Cutout mounted reclosers function similarly to line reclosers, adding reclosing capabilities to single and three phase locations where a recloser would not typically be used for fault isolation. To-date, the Company has installed cutout mounted reclosers in over 130 locations across the State since 2015.

Underground infrastructure

Underground distribution systems are largely insulated from storm impacts that affect overhead systems. However, increased temperatures, flooding, more frequent freeze/thaw cycles throughout the winter months, and other climate impacts can exacerbate and accelerate asset condition concerns with underground infrastructure. The Company has robust asset replacement programs in place to proactively identify and mitigate risks associated with this equipment. The Underground Cable Replacement program prioritizes underground cable replacements according to safety, customer impact if the cable were to fail, asset condition, and reliability. A separate program addresses underground cable systems that serve residential and commercial developments and exhibit a history of failures. These cable replacement/rehabilitation programs improve the resiliency of underground systems by addressing cables at a heightened risk of failure and improving the overall asset health of the system.

An example of other underground assets that have been targeted programmatically is oil fused cutouts. Oil fused cutouts are submersible fusing and switching devices used in some underground systems. These devices present a unique reliability and resiliency challenge, as safety considerations have led to the adoption of work practices prohibiting switching of oil fused cutouts with personnel in the enclosed space. Remote operating tools and procedures increase the complexity and duration of both outage restoration activities and non-emergency switching procedures. Since 2002, the Company has actively been executing a program to remove all oil fused cutouts from its system.

Flood mitigation

Flooding presents a significant environmental risk to electric infrastructure, particularly in substations. In the spring of 2010, a series of heavy rain events caused historic flooding in the state of Rhode Island. Eight substations in the Company territory were completely flooded and subsequently had to be removed from service. The impacts of this event included significant customer outages and loss of high value substation equipment. The Company recognizes the threat that floods pose to all its substations, including those located in the Commonwealth.

Following these flood events and concerns stemming from the impacts of Hurricane Irene and Superstorm Sandy, the Company completed an assessment of the likelihood of substations throughout its service territory sustaining damage during a flood event. The study compared substation locations to the flood zones in Federal Emergency Management Agency (FEMA) Flood Insurance Rate Maps. Substations located within the 100-year flood plain have a 1% probability of being reached by flood water. In these substations, the base elevation of equipment and critical buildings within the substation was used to determine how deeply they would be submerged during

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[1] This 560/800A refers to the current rating of the recloser

a 100-year flood. This analysis identified thirteen substations across the State as having a high risk of flooding. System impacts from a flood event could include substation removal from service and a high probability of damage to critical equipment such as transformers, circuit breakers, and relays. Customer outages would likely occur while the substation equipment is not available. Flood mitigation measures have been or are being taken at all thirteen of these substations. Mitigation measures include:

- Immediate response actions such as the installation of Timber Wall and Floodstop barriers (rapidly deployable earth-filled barriers), flood barriers, and supplemental flood risk reduction elements such as pumps, plugs, and generators to displace water inside substations from general rainfall and potential flood barrier leaks (status complete);
- Further evaluations of flood risk that resolve system performance concerns, including interactions with external agencies such as submitting a Conditional Letter of Map Revision ("CLOMR") to FEMA (status complete); and
- Incorporation of flood mitigation measures into planned infrastructure development projects at the identified substations.

These measures are intended to reduce the risk of damage during a flood event, enhancing the Company's substations' resiliency to this potential climate change impact. Section 10.3 contains details on additional actions that the Company is taking to identify and mitigate anticipated flood impacts at its substations.

Targeted hardening and reliability efforts

The Company conducts regular analysis of the distribution system's reliability as part of larger area study efforts and in response to acute system concerns. The Company conducts annual Engineering Reliability Reviews on a subset of circuits whose reliability metrics (frequency and duration) were in the bottom 5% of the Company's circuits for the previous year. This results in analysis of approximately 60 distribution circuits each year to identify measures that will improve their reliability and resiliency in subsequent years. The solutions typically implemented by the Company include line recloser installations, circuit reconfigurations, reconductoring bare wire with tree wire or spacer cable, FLISR installation, and targeted vegetation management. Recommendations stemming from these reviews enhance the ability of these circuits to withstand environmental conditions contributing to their relatively poor reliability and decrease the time it takes for the system to recover from damage.

Emergency response plan

Regardless of how hardened and/or resilient the distribution systems are, it is inevitable that the Company will experience and must be prepared to respond to extreme weather events that impact its infrastructure significantly. The Company has established the Massachusetts Electric Emergency Response Plan ("ERP") for the purpose of managing outages caused by storms and other natural disasters, major equipment failure, or other events. The ERP is intended to be simple, flexible, and easily adapted to specific emergencies, and includes procedures that will be adhered to by the Company's electric subsidiaries in Massachusetts whenever an emergency occurs.

The ERP provides the framework for the orderly response of Company resources during emergency events. These procedures provide instruction on actions taken during emergency events classified as Type 1, 2, and 3. The ERP uses the National Incident Management System (NIMS), which is a comprehensive national approach to incident management applicable at all levels of the Company's Emergency Response Organization ("ERO") and across functional disciplines. It is focused on public safety, workforce safety including safety of outside assistance, and addresses the operation of Company Emergency Operation Centers. The ERP meets the requirements for preparing and filing annually and incorporates regulatory orders into its development. The ERP has been developed in accordance with all applicable regulations and is designed based on the principles of Incident Command System ("ICS") and the Company's Group Crisis Management Framework. The Company conducts training, drills, and exercises on an annual basis to evaluate the effectiveness of this ERP, with the New England State Emergency Response Functional Exercise completed by August 1 of each year. The ERP is also reviewed with revisions identified and submitted to the Department no later than May 15th of each calendar year.

The ERP and its associated organizations and training allow the Company to respond effectively and efficiently to emergencies across the State, including those caused or influenced by climate change.

Enhanced fault detection

Early Fault Detection (EFD) is technology that detects and locates defects in electrical infrastructure before they develop into electrical faults that cause fires, equipment damage and electrical supply interruptions. The defects that EFD detects include incipient asset failure due to degradation, damage, and asset compromise by external factors such as vegetation. Utilities use EFD Systems to monitor both AC and DC utility distribution and transmission power line networks and substations, electrical infrastructure in large industrial sites, and electrical rail networks. The proposed expansion of EFD in the Plan is designed to deploy onto a blended mix of "identified problem circuits," as well as identified EJC communities within the Company's service area.

10.3 Distribution Resiliency Hardening Programs

The Company has developed a resiliency strategy which establishes an approach using existing readily available system outage data to identify, prioritize, and mitigate Company circuits that have demonstrated historical resiliency challenges. The strategy focuses specifically on hardening investments that are anticipated to increase the resiliency of the distribution system. These hardening investments include spacer cable reconductoring, targeted overhead line hardening, targeted undergrounding of single-phase side taps, and targeted undergrounding of mainline three phase conductor. The resiliency strategy proposes to invest in targeted hardening and resiliency projects through 2030. As the Climate vulnerability assessment effort described in Section 10.4 progresses, it will inform future revisions to the Resiliency Standard to incorporate future-looking climate projections in hardening investment decisions.

10.4 Asset Climate Vulnerability Assessment (such as Flood Impacts, Wind Speeds, High Heat Impacts, Ice Accretion, Wildfire and Drought)

Asset climate vulnerability assessments consider the impacts of climate change over the next several decades. Understanding changing climate conditions and the risk to assets ensures appropriate mitigation efforts are considered to protect existing assets and build climate resiliency into future assets. The typical lifespan of an electrical asset is often 50 or more years, so future climate hazards need to be considered during the planning process to avoid premature asset repair or replacement. For example, the location of a proposed new substation may not be in a coastal flood prone area today, but climate model projections may indicate that it will be in 10 years. Understanding the future climate hazards will allow the making of informed design decisions and update hardening programs to protect the Company's assets and improve customer reliability into the future. Investments associated with the outcomes of climate vulnerability assessments will be included in the base rate case.

10.4.1 Asset Climate Vulnerability Assessment Overview

Asset climate vulnerability assessment is the process of using climate model projections to determine the future risk to the Company's built and future electric infrastructure for specific climate hazards. It includes understanding the geographical characteristics of both climate hazards and their assets, the vulnerability of the assets and the inherent exposure. A system wide climate vulnerability assessment has been initiated to develop adaptation plans to minimize future climate hazard risk.

10.4.2 Climate Hazard Risk Overview

Climate hazard risk relates to the physical and operational impact of changing climate hazards to electric assets due to increasing chronic hazards and intensifying extreme acute hazards as a result of global warming. Climate hazard risk consists of three components, as shown in Exhibit 10.5:

Exhibit 10.5 – Climate Risk Hazard Review Calculation

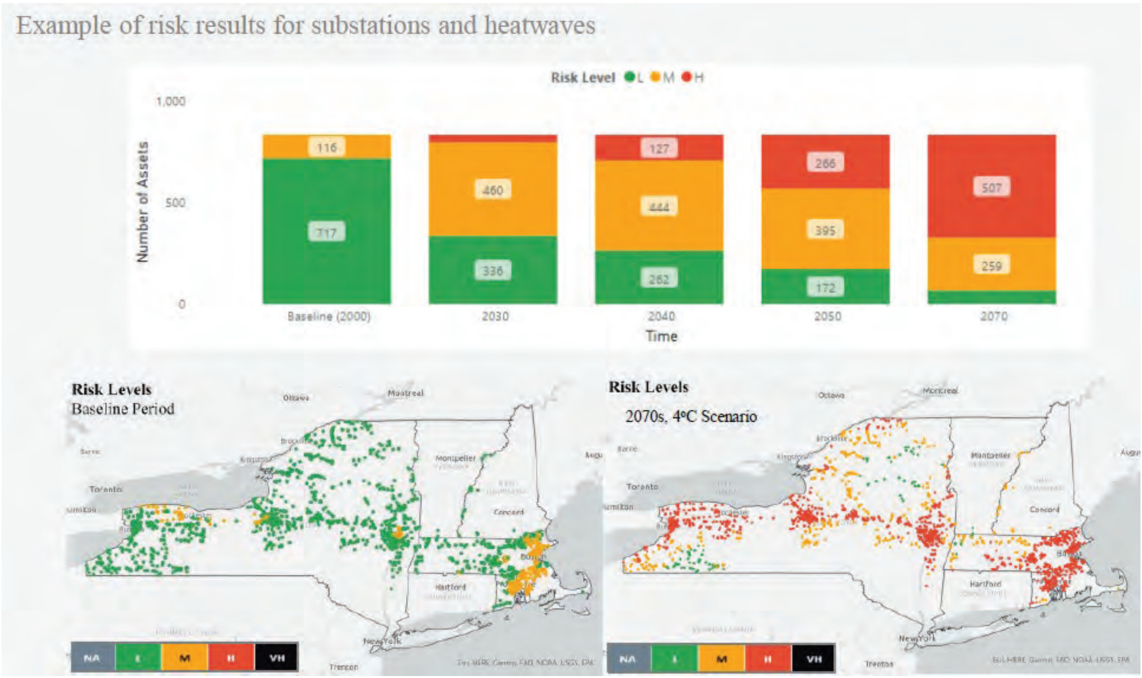
Risk = Hazard x Vulnerability x Exposure

Hazards are climate events which can cause damage to assets or infrastructure. Vulnerability captures the asset sensitivity to climate hazards. Exposure incorporates the asset location, relative to the hazard location.

To identify climate hazard risk, an internal tool was developed called the Climate Change Risk Tool (CCRT). The CCRT an industry leading tool that allows the Company to accurately map how their electric infrastructure may be impacted by climate hazards – such as floods or heatwaves – and to take early preventative and adaptive measures to significantly lower the risk of disruption to power networks, equipment, and communities decades into the future. The data in the tool was sourced from the Fourth National Climate Assessment (NCA4). These assessments include data from FEMA, the National Oceanic Atmospheric Administration (NOAA) Physical Sciences Laboratory, Environmental Protection Agency (EPA), and academic literature. The scenario data is modelled using the Intergovernmental Panel on Climate Change's (IPCC's) Representative Concentration Pathway (RCP) scenarios of RCP4.5 and RCP8.5. The following table includes a description of the two RCP scenarios to provide additional context.

RCP	Description	CCRT Represented Scenario
RCP 4.5	Considered an 'Intermediate Scenario' with global warming increases range between 1.1°C and 2.6°C by 2100	'2°C Scenario'
RCP 8.5	Considered a 'Worst-case Scenario' with global warming increases range between 2.6°C and 4.8°C by 2100	'4°C Scenario'

Exhibit 10.6: CCRT Output Sample Showing Long-term Projections that Risk Heatwaves Will Have to Substations.



Using the CCRT, specific assets having high risk to specific chronic climate hazards were identified and adaptation measures have been selected to lower the risk. Acute climate hazards related to chronic hazards that have a high impact on electric assets were also identified through conversations with experts, current events, and available resources, but are not yet modeled in the CCRT.

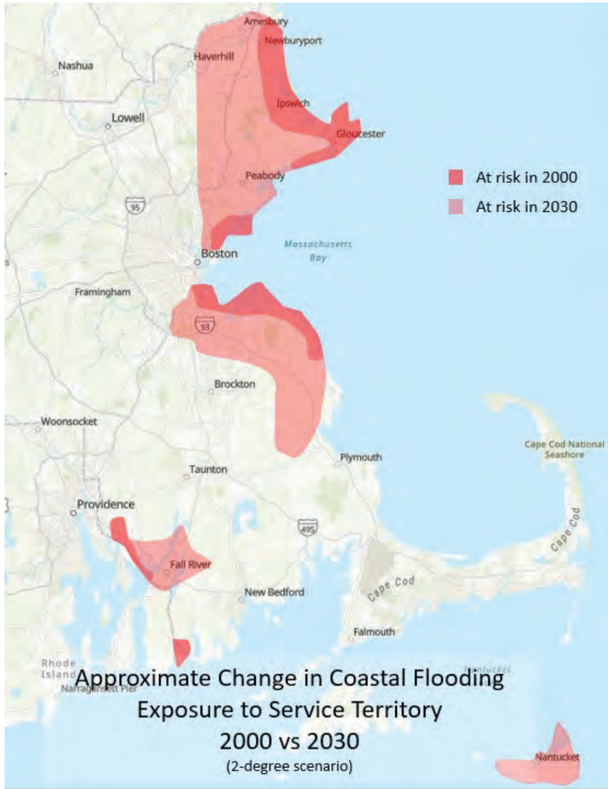
10.4.3 Climate Hazards

Five primary hazards were identified (using the CCRT and other available resources) that have the greatest potential impact on the electric network. The following sections summarize the changing risk levels related to coastal flooding, high-temperature, extreme wind, wildfire, and low-temperature.

Coastal flooding

Considering the projections of sea level rise, asset exposure to coastal flooding expands further inland over time, as shown in the following Exhibit 10.7. Water infiltration can significantly impact substation equipment and above-grade components of underground distribution line systems, resulting in physical and electrical failure and accelerated corrosion.

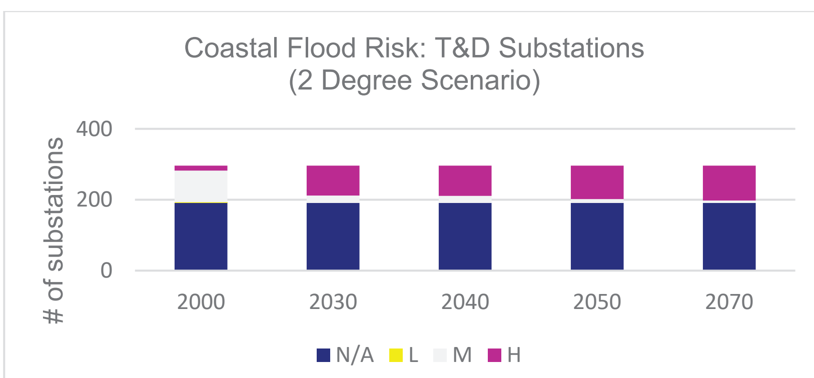
Exhibit 10.7 - Approximate Change in Coast Flooding Exposure



Substations

A review has been completed to identify substations at risk of coastal flooding over time. The following chart, Exhibit 10.8, shows the change in substations at high risk for coastal flooding, when considering the 2-degree scenario.

Exhibit 10.8 – Coastal Flood Risk: Substations



The Company has had a significant focus on flood mitigation risk as described in the previous section. Flood risk is reviewed approximately every 10 years as FEMA maps are updated. Considering the output from the climate model, substations further inland have been identified in addition to those identified through the FEMA maps. Note that the model's granularity does not evaluate elevation change at each specific substation site, so the risk must always be further evaluated at each individual site.

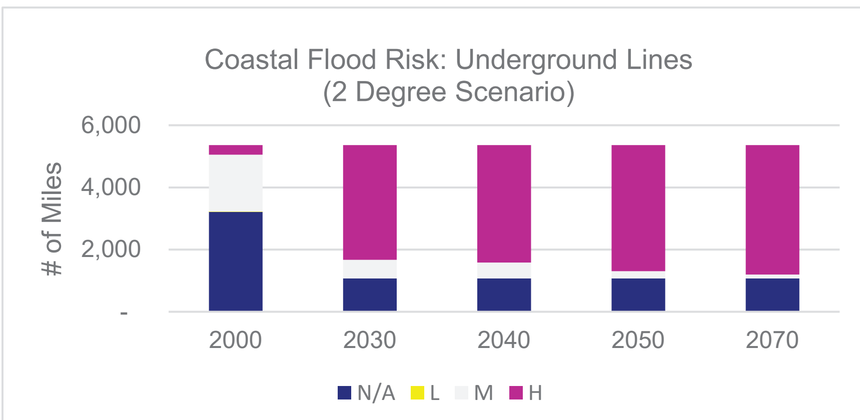
Of the approximately 300 total substations located across the State, about one third are located within an area that is at flood risk now or in a future year. About half of those substations have had flood mitigations projects completed, in progress or deemed unnecessary based on site-specific reviews. For the remaining sites, flood mitigation will be incorporated in the planned projects outlined in Section 6 and temporary flood mitigation will be considered where there is no planned work, after site-specific elevation reviews.

According to NASA sea level projections[2], sea level rise in Boston is expected to increase between 0.52m (RCP4.5) and 0.59m (RCP8.5) in 2070 and will be taken into consideration in the actual elevation design. Furthermore, the Company is beginning to discuss increasing their flood mitigation design criteria to a more stringent criteria to account for future flood levels above the current design standard for all planned projects as well as assessing existing flood mitigation measures.

Underground distribution lines

The CCRT identified underground lines at risk for future coastal flooding. The following chart, Exhibit 10.9, shows the change in risk for coastal flooding considering the 2-Degree Scenario over time. Like substations, assets further inland are exposed to coastal flooding.

Exhibit 10.9 – Coastal Flood Risk: Underground Lines



In general, the underground system is designed to be submersible. The above ground components of underground systems (e.g., padmount transformers and switches) are the most vulnerable to coastal flooding. To address these impacts, the primary mitigation action under consideration is to apply the coastal design storm hardening standard further inland which specifies the use of specific material and equipment types that are more resistant to corrosion and the requirement to increase elevation of electric equipment (e.g., transformers and switches).

River flooding

River flooding risk was reviewed as part of this assessment, but the models indicate only a slight increase in risk. NOAA's historical and projected precipitation[3] data was reviewed as the risk of river flooding is directly related to projected precipitation. The following table, exhibit 10.10, includes the projected number of days per year with greater than 3" of rain.

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[2] Sea Level Projection Tool – NASA Sea Level Change Portal

[3] https://crt-climate-explorer.nemac.org/

Exhibit 10.10 – days w/ >3" rain

	Days/Year w/ >3" of Precipitation		
County	**2000s**	**2070s RCP4.5**	**2070s RCP8.5**
Berkshire	0.1	0.2	0.2
Bristol	0.1	0.2	0.3
Essex	0.2	0.3	0.3
Franklin	0.1	0.1	0.1
Hampden	0.1	0.2	0.2
Hampshire	0.1	0.2	0.2
Middlesex	0.2	0.3	0.3
Nantucket	0.1	0.2	0.3
Norfolk	0.2	0.3	0.3
Plymouth	0.2	0.3	0.3
Suffolk	0.2	0.4	0.4
Worcester	0.1	0.2	0.2

There is variability year to year (e.g., 0-1.5 days for Worcester County) and an extreme flood event could be seen within the Company's service territory in any given year outside the projected values. Substation sites located near rivers will continue to be reviewed for flood risk.

Heatwaves/high temperature

Increasing ambient temperature has the most significant impact on transformers, overhead line conductors and protection and control equipment. The vulnerabilities include increased sagging, which can endanger the public, increase the potential for outages and lower the electrical capacity of the line, decreased life expectancy, and decrease in capacity. The following tables, Exhibit 10.11 through 10.14, show the impact temperature change can have over the coming decades for both transformers and overhead line conductors. There is a clear trend of an increase in miles of distribution lines, transformers and substations exposed to high impact temperatures. Please note the values shown in the charts are approximate.

Exhibit 10.11– Heatwave: OH Conductor

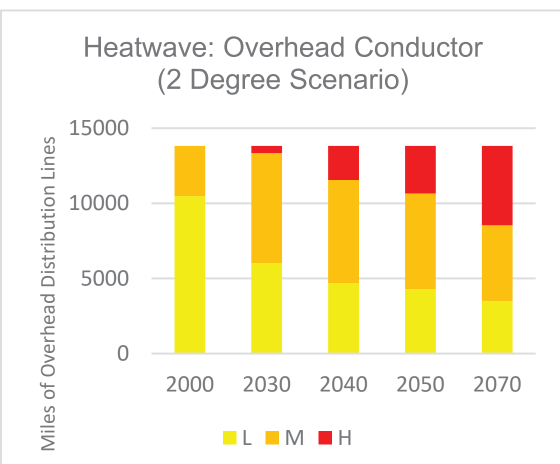


Exhibit 10.12– High Temperature: OH Conductor

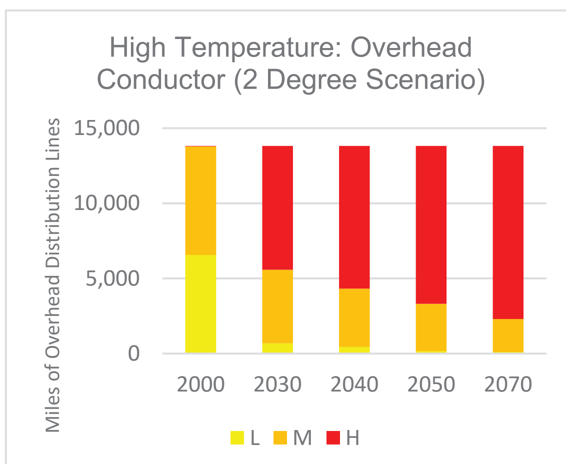


Exhibit 10.13 – Heatwave: Line Transformers

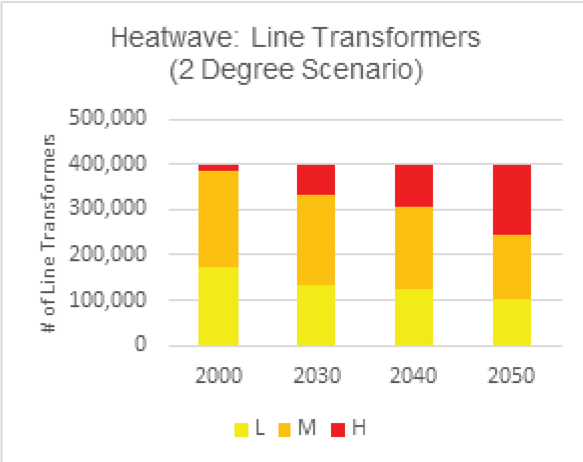
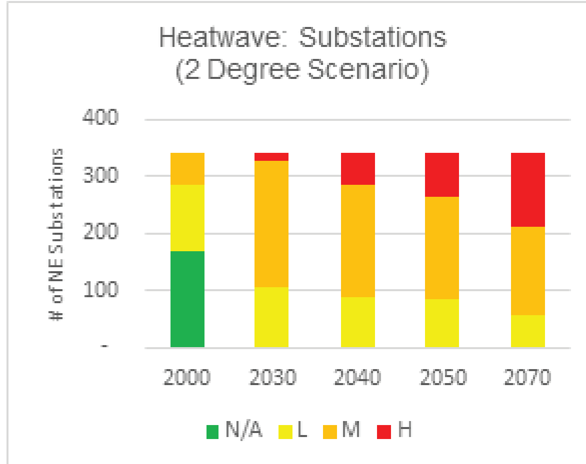
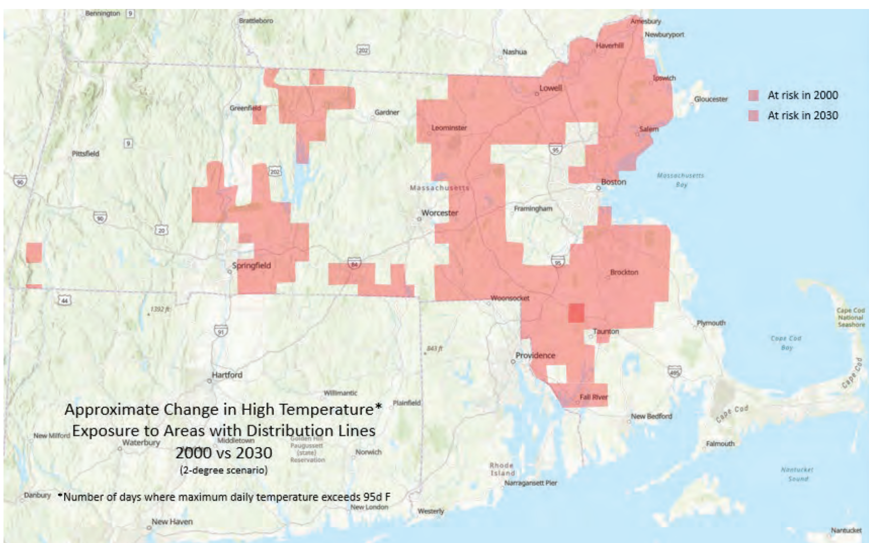


Exhibit 10.14 – Heatwave: Substations



The data above indicates more assets will be exposed to temperatures exceeding 95F over the next several decades. Exhibit 10.15 is a map depicting the difference between 2000 and 2030.

Exhibit 10.15 – Temperatures >95F: 2000 vs. 2030]



To further understand the risk of increasing temperatures, NOAA's historical and projected temperature[4] data was reviewed to better understand the frequency of high temperature events in the State. The following table, Exhibit 10.16, includes the projected number of days per year with greater than 105F temperatures.

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[4] https://crt-climate-explorer.nemac.org/

Exhibit 10.16 – Days/Years > 105F

County	Days/Year w/ max temp > 105F			
	2000s BL	2050 RCP4.5	2070s RCP4.5	2070s Range
Berkshire	0	0	0	0-0.3
Bristol	0	0.1	0.1	0-1.3
Essex	0	0.1	0.2	0-1.7
Franklin	0	0.1	0.2	0-3.6
Hampden	0	0.1	0.2	0-2.9
Hampshire	0	0.1	0.2	0-2.8
Middlesex	0	0.1	0.3	0-4
Nantucket	0	0	0	0-0
Norfolk	0	0.1	0.1	0-2.2
Plymouth	0	0	0.1	0-1.3
Suffolk	0	0.2	0.3	0-3.7
Worcester	0	0	0.1	0-1.7

While the average temperature increases are quite low, the variability in range shows the State could see days with greater than 105F.

The development of conductor design uses a standard ambient temperature of 100F. There are ongoing conversations to determine if the ambient temperature should increase to 105F and what the impact of such a change would have on standard pole height and spacing. Additionally, a study is being initiated to evaluate transformer standard sizes considering changing demands and increasing ambient temperature. The potential impact of standard changes would be an incremental cost increase to each project ranging from <1% to 5%, once the standards are determined and implemented.

The Company will also plan to evaluate control cooling systems and control building backup power standards to minimize the impact of increasing temperatures.

The impacts of increasing ambient temperature go beyond standards and design criteria and begin to impact forecasted demand and equipment ratings. As climate change continues to impact the Company's customers and territory, including increased extreme high temperature days, the incremental capacity enabled through the investments described in Section 6 will provide additional flexibility to respond to these emerging resiliency challenges. Consideration of ambient temperature increases and the impact on loading will be considered further for the base forecast scenario.

Extreme wind and ice accretion

As outlined in previous sections, a robust storm hardening program has been implemented. Looking forward to projections of both extreme wind events and icing events can provide insights on how to adapt the Company's storm hardening program considering the impact of climate change.

Global

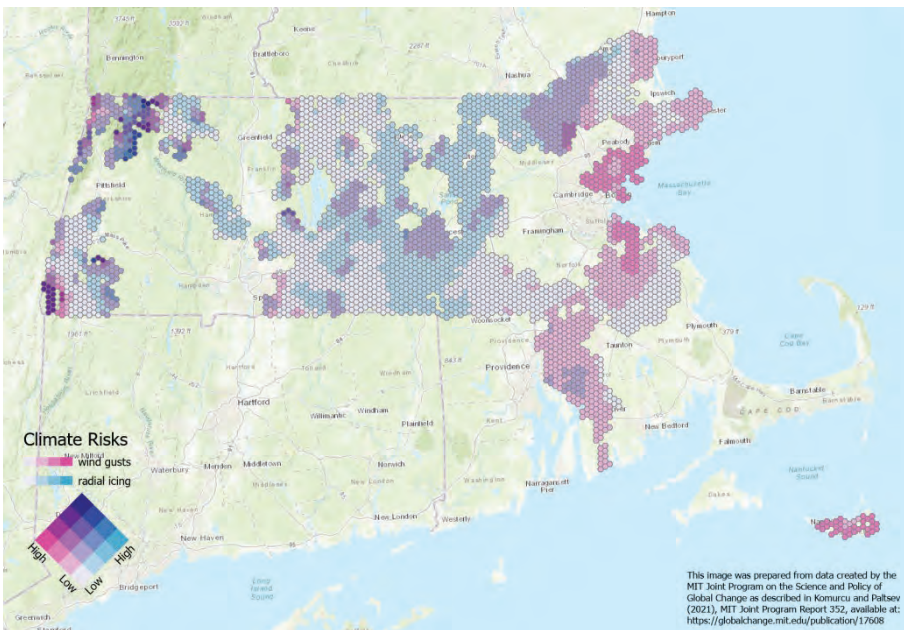
Global oceans have been remarkably warmer than they have been historically and the North Atlantic Basin has been experiencing record high sea surface temperature. Hurricane severity is likely to increase because of high sea surface temperature, sea level rise, and atmospheric changes (e.g., warming of mid-latitudes) but the degree of intensity increase is uncertain. The frequency of hurricanes will still be driven by the oscillation between La Niña (increased hurricane activity) and El Niño (decreased hurricane activity) phases.

Increased air temperature can hold more moisture and therefore more precipitation is expected to fall at higher temperatures year-round. In areas prone to snowfall, there is an increasing risk of icing events as winter temperatures increase and precipitation falls around 32F.

Northeast

Because of the expanding tropics (warming of mid-latitudes), the latitude at which a hurricane is the strongest is expected to move northerly and therefore the risk of experiencing more intense winds speeds in the Northeast is growing. A study conducted in partnership with Massachusetts Institute of Technology identified several regions across the State that could see >120mph wind over the years 2025-2040. The same study also identified radial icing events over the years 2025-2040 and it concluded several areas are at risk of radial icing greater than 0.75 inches.

Exhibit 10.17 – Wind Gusts and Radial Icing Climate Risk Map



Note in the map above: 'High' Radial Icing (blue) is defined as 0.72" to 0.95" and 'High' Wind Gusts (pink) are defined as 98mph to 121mph

Electric infrastructure impact

Distribution lines will continue to have the highest vulnerability to extreme wind and icing events, with vegetation contact being the primary risk of outages. Optimized vegetation management activities, as outlined in Section 10.2, have proven to positively impact the reliability of the electric network. Tree wire, anti-cascading structures and FLISR schemes will further minimize the impact when tree contact does occur.

Adaptations Under Consideration:

As more severe and intense weather is projected, hardening programs and standards should adjust accordingly. While there is a robust hardening program in place today, there are additional enhancements under consideration to adapt to future climate hazards:

Pole Design

The current extreme wind pole design is based on the NESC Rule 250C. For poles in southern coastal Massachusetts and those greater than 60 feet, a maximum wind speed of 120mph is used. For locations further north with less wind, and for poles less than 60 feet, a wind speed of 40mph is used. Distribution lines are also designed for 0.5 inches of radial icing concurrent with a 40mph wind. The impact of increasing wind speed and radial icing is under review and acceptance of this standard would likely result in taller, higher-class (stronger) poles.

Fiberglass Crossarms

Fiberglass crossarms are currently specified for dead-end crossarms to prevent the impacts of a cascading failure. The impact of expanding the use of fiberglass crossarm instead of wood crossarms in additional locations will be evaluated.

Targeted underground

Targeted underground continues to be discussed and evaluated as an option to harden the distribution network. Initial targeted undergrounding opportunities have been identified through Resiliency Strategy investments described in Section 10.3 and will continue to consider undergrounding opportunities to mitigate emergent climate risks, operational challenges, and reliability/resilience performance concerns focusing on communities identified above. This preliminary review of future wind and ice projections indicates Berkshire County is at highest risk for both hazards and additional targeted underground will be explored in this area in future years. The following table, Exhibit 10.18, provides an overview of distribution line assets located in Berkshire County.

Exhibit 10.18 – Berkshire County Distribution Lines

Berkshire County	
OH	**Mileage**
3 Phase	379
1 Phase	565
Total	943
Underground	**Mileage**
3 Phase	51
1 Phase	157
Total	208
Total Mileage	1151

Additionally, the expansion of distribution infrastructure through the execution of the Future Grid investment plans will introduce feeder routing constraints which, when combined with resiliency concerns in alignment with the climate vulnerability assessment, may lead to an increase in underground infrastructure particularly around congested areas near substations and in highly populated areas. Underground infrastructure in close proximity to substations improves the reliability and resilience for the highest number of customers compared to undergrounding portions of circuits further from substations.

Wildfire

The current risk of wildfires in the State is low[5] but with increasing extreme events across the US, it is an emerging risk under review. While precipitation is expected to increase in future years [6], some predict the precipitation will fall more intensely during shorter periods of time, meaning there will likely be longer periods of seasonal drought. The Company is beginning to review this risk now and

[5] Map | National Risk Index (fema.gov)
[6] Climate Explorer (nemac.org)

expects the review to continue over the next year and will consider best practices from peer utilities in California. Vegetation management programs, inspection and maintenance programs, and storm hardening programs (e.g., tree wire and targeted undergrounding) are significant components of published leading wildfire mitigation plans to help mitigate wildfire risk. Emergency response plans are another key component which include training, exercises, communication strategy, and emergency de-energization protocol among many other activities. The Company will continue to review these best practices and will implement mitigation measures appropriate for the geographical risk level.

10.5 Framework to Address Climate Vulnerability Risks through Resilience Plans

The Company is committed to taking proactive action to address the impacts of climate change on the electric system. Climate change is no longer a "future threat". Its effects, including observable changes in average temperatures, precipitation trends, and extreme weather events, are being witnessed today. Climate change is anticipated to give rise to more frequent extreme events and utility providers must plan for their potential effects. The Company's framework to address climate vulnerabilities is outlined in the phased approach in Exhibit 10.19, and the identified adaptations are included in resilience plans as described in Section 10.4.

Exhibit 10.19 – Framework for Vulnerability Risk Assessment

- Phase 1: Validate the climate science, climate hazards and assets in scope
- Phase 2: Assess the vulnerability of each asset to each climate hazard.
- Phase 3: Prioritize the assets identified in Phase 2 using the following framework: Climate Vulnerability Risk = Exposure x Potential x Hazard
- Phase 4: Develop adaptations to address assets with the highest risk.

The process follows the Institute of Asset Management (IAM) guidance for climate change action planning. For developing climate change adaptation plans, the IAM recommends the use of risk-based models, considering the increasing likelihood and consequence of asset failure/degradation due to climate change and the impact this might have on the delivery of the organization's goals. If unaddressed, the climate vulnerabilities identified could have significant implications for the Company assets and its ability to deliver affordable, safe, and reliable electricity to its customers. Projected changes in temperature, heatwaves, flooding risks, and extreme events that lead to high wind speeds, storms, and icing may aggravate rates of asset failure, cause more outages, and impacting system reliability. These impacts could also mean increased operational as well as repair and restoration costs. In addition, these impacts may raise concerns around workforce and public safety. This framework will highlight priority areas where the Company can focus its future climate resilience planning and investments decisions.

Through the initial climate vulnerability assessment, it can be concluded that more severe and intense weather will be experienced in future decades, and hardening programs and standards should adjust accordingly. Most of the adaptations under consideration are likely to be in the form of standard updates such as increased pole strength, increased ambient temperature, and expansion of coastal flood design which would be applied to all new and replaced assets once the standard is implemented.

Targeted adaptations, such as permanent and temporary flood mitigation, are prudent to plan for now. As a result of the climate vulnerability assessment, the Company plans to invest in additional temporary flood mitigation projects at five substation locations as part of “core operations” in the core rate case. The substations will be selected following site-specific evaluations. Temporary and permanent flood mitigation will be planned for the remaining substations in future years.

Climate projections can shift overtime and the risk of climate hazards to the Company's infrastructure must continue to be assessed. Annual funding will be requested in the core rate case to maintain and improve the functionality of the CCRT to ensure continual climate model updates and asset risk evaluations.

Finally, the Company will continue to learn from the climate vulnerability assessment and the planned targeted underground projects to identify additional opportunities to underground distribution lines in future years.

The Company acknowledges that while the findings from the assessment are critical to resilience planning and investment decisions for the next 5-20 years, the vulnerability of its assets to different climate hazards will continue to evolve. This assessment must therefore be seen as part of an ongoing process through which the Company will regularly evaluate and adapt its resilience planning into the future.

Section 11

Integrated Gas-Electric Planning

This section describes of the importance of integrated planning across gas and electric utilities and provides a pathway to begin advancing such planning in the Commonwealth.

Key Take-Aways

- Integrated energy planning across EDCs and gas LDCs will become increasingly important as the Commonwealth pursues the electrification of heating. An orderly transition of customers to electric heating allows for benefits such as avoiding gas infrastructure investment via targeted electrification of gas customers and ensuring the local electric network is ready to pick up the load.
- The status quo presents challenges to integrated planning including lack of service territory overlap among EDCs and gas LDCs, historically siloed planning processes, and lack of regulatory and policy enablers.
- Kicking-off concerted collaboration efforts across the Commonwealth's EDCs and gas LDCs with other key stakeholders is an important first step.
- Pathfinding work to define integrated planning capabilities, pilot them, and scale them should start soon, and the Future Grid Plan seeks initial seed funding for such work.

11.0 Integrated Gas-Electric Planning

What is integrated gas-electric planning and why is it needed?

Transitioning from fossil fuel heating to electrification is a critical component to a decarbonized future. Today, however, much of the Commonwealth relies on natural gas for space and water heating as well as cooking. Electrification policies and programs need to direct Massachusetts homes and businesses toward electrification when the opportunities arise (e.g., at end of life for a legacy fossil heating system). By forecasting growth in comprehensive electrification demand and investing in electricity system capacity to serve that demand, the EDCs can enable that electrification transition for customers. With this transition to electrification, there is an opportunity to fine-tune decisions across customer demand-side programs, electricity network investments, and gas network investments to provide for a more reliable and affordable whole energy system.

Gas and electric utilities generally plan and operate their networks in isolation from one another, even when they are affiliated companies with a common parent company, because historically there has been little need for coordination. Moreover, customer demand-side programs have been only loosely integrated with infrastructure planning. Integrated energy planning (IEP) will be essential to achieving the Commonwealth's decarbonization goals and mandates while providing gas and electric customers with safe, reliable, and affordable service during the transition. For example, the full electrification of gas customers not coupled with the necessary electric infrastructure improvements will result in an unreliable grid; conversely, there may be opportunities to target EH in ways that avoid gas network investments. The LDCs and EDCs are uniquely positioned to work collaboratively in development of the ultimate electric distribution and gas infrastructure plan necessary to meet the Commonwealth's decarbonization goals. An orderly transition to decarbonization that includes coordination and collaboration on gas and electric system planning and customer demand-side programs outside of traditional measures offers several potential solutions to optimize overall energy system costs and reliability:

- Gas utilities may be able to avoid network reinforcements if targeted electrification can address gas load growth in the near term, which might require accelerated electricity network heat load serving capacity investments;
- Targeted electrification could be an alternative to leak-prone pipeline replacement if electricity network capacity can support the incremental load in time;
- In locations where electrification adoption is exceeding the electrification hosting capacity, hybrid gas/electric heating solutions will be needed in the short term to maintain system reliability. The entity delivering demand-side programs will need to be aware of these constrained areas and work with customers to develop the hybrid solutions;
- Correspondingly, in areas where the pace of electrification adoption is projected to exceed the electrification hosting capacity, the electric companies may need to accelerate electric improvement plans in those areas.

The purpose of IEP is to help realize these benefits. IEP will collectively help enable the Commonwealth to:

a) Prudently build out the electric system in the right locations at the right time to prepare for conversion of fossil heating to decarbonization and;
b) Make calculated decisions about where on the gas system to prioritize investment in the gas network (e.g., leak-prone pipe repair or replacement) and/or plan to decommission sections of the gas network in favor of electric heating or alternative heating solutions, such as networked geothermal.

IEP is the 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.

IEP presents new and challenging questions that the EDCs look forward to collectively addressing together, in partnership with Commonwealth stakeholders and the other electric utilities, gas utilities, and municipal electric companies.

11.1 Challenges in Considering Integrated Gas-Electric Planning

As highlighted in prior sections, multiple areas of the electric distribution system are at or above reliability limits and 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 systems convergence as heating and transportation sectors transition to the electric sector. Further complicating this is that gas and electric 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. Below are key challenge areas that need to be overcome:

1. **People, process, technology:** While utilities have planning staff on gas and electric sides, 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. And this is to be expected with past practices requiring little to no coordination planning efforts even across affiliated operating companies. The first challenge in kicking off a coordinated gas-electric planning 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 is helpful to look at the share of gas customers served by the affiliated EDC since electricity service is universal. Only 28% of the Company's gas customers are also the Company's electric customers. Given this limited level of overlap between affiliated utilities' gas pipeline networks and electric networks and vice versa, the need for coordinated utility planning is critical. For example, when a gas LDC identifies a constraint on its gas system, in order to reduce that gas demand with deployment of electrification solutions, an unaffiliated EDC may need to upgrade their electric infrastructure – necessitating a comprehensive data exchange between the gas LDCs and EDCs regardless of their parent company affiliations.
3. **Customer adoption:** Electric and gas utilities can transform their capabilities for IEP with the most robust processes, software, and data for developing plans, but actually realizing the benefits from IEP depends on implementing a deliberate and orderly transition of customers off of gas usage, at least in specific areas by specific times. The best plans to optimize across gas and electric network investments will come to naught if customers do not adopt electrification and do not transition from gas usage when and where needed. 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 certain date.
    a. The current approach to demand side electrification incentive programs does not provide for this orderly transition because time-bound, universal adoption of electric measures (e.g., EHPs, electric boilers, electric stoves) by customers served by specific gas infrastructure is a new objective that raises important program design and implementation questions that will need to be addressed. Specifically, should new incentives be designed in gas-constrained areas, or is that a prioritization and an extension of the existing customer demand-side programs? If the latter, thoughtful consideration needs to be given to achieving the universal adoption of EHPs in those areas within the allotted time.

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 and electrification load-serving 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. This is an area that 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 EHP technology and other EE technologies and will continue to develop these proposals in the EE Three Year Plans, in concert with the EEAC and Equity Working Group members and subject to the approval of the Department.

4. **Novel questions:** IEP 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 IEP, including by targeted electrification of gas network segments where there will be sufficient electricity network hosting capacity based on the ESMPs. This information can inform the gas utility planning processes and will pave the way for initial information sharing on the status of the 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 (i.e., locations where there will be network reinforcement to readily support more EHP adoption), which can be used to inform review and feedback on gas utility investments and the Commonwealth's comprehensive electrification policies and programs. 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 community served by the EDCs within the Commonwealth. And because of various upgrades implemented in different years within the 10-year period, a community's available electrification hosting capacity may increase over the forecasting period.

11.3 Coordinated Gas-Electric Planning Process

The EDCs have spent time engaging with leading peers across North America and in the UK on IEP and conducting preliminary internal engineering studies to gather insights on how such planning could work in practice. While some utilities, states, and countries are leading the way, they are all still in a pathfinding mode. No one has figured it all out yet.

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:

- 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 new gas infrastructure.
- Stakeholder input will be essential to coordinated planning, including giving affected communities a voice in the planning.

As an evolving and novel capability, IEP will require changes to utility processes, people, and technology. More work is needed to fully detail out what a fully mature capability will require, but some initial requirements are below:

Process:

LDC-EDC Data Exchange

- 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 investment plans by year between EDCs/gas LDCs with supporting planning analyses

Joint Utility Planning Working Group

- Establishment of Joint Utility (gas 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 long-range capital plan

Planning Tools:

- 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 execute on their respective Gas and Electric Plans, assessment of different gas demand scenarios resulting from targeted electrification solutions, and executing on coordination process laid out above accounting for drafting annual reports will require incremental FTEs for gas/electric engineering

11.4 Safe and Reliable Gas Infrastructure

In the near term before comprehensive electrification and other policies and programs fully slow, stop, and reverse gas demand growth, gas utilities will have network reinforcement needs to accommodate this near-term demand growth. Even more importantly, 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.

There may be “low-hanging fruit” to address first via IEP to identify localized gas network reinforcements driven by demand growth and relatively isolated leak-prone pipe segments slated for replacement that could be avoidable via targeted electrification. IEP offers the potential to leverage targeted electrification to avoid some of these gas infrastructure investments.

11.5 Gas-Electric Coordinated 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 municipalities. Failure to establish appropriate cross-utility collaboration and data sharing frameworks means that most of the Commonwealth would not have any integrated gas and electric planning, and thus would not benefit from well-coordinated gas and electric plans.

Thus, establishing a gas and electric coordinated planning working group with representatives from the different Commonwealth electric and gas utilities, DOER, AGO, and key affected stakeholders (e.g., environmental, consumer) will be critical.

The working group’s objectives should include the following:

- Develop a shared understanding of the overlapping utilities’ networks today and their network planning processes
- Leverage learnings and best practices from other leading utilities in this space (e.g., California, UK, Québec, Europe)
- Conduct joint gas-electric planning studies to generate learnings and identify near-term opportunities to optimize investments:
    i. Exchange of gas and electric distribution constraints
    ii. Conduct and share planning studies to resolve constraints
    iii. Detailed 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 IEP 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 fruit” 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 IEP
- Provide recommendations for how the three-year EE program process should align with IEP
- Assess future regulatory decisions as well as identify additional policy and regulatory enablers for IEP
- Explore how best to provide transparency and opportunities for input to various stakeholders

11.6 Next Steps

Pending GMAC 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 would proceed with the establishment of the Joint Utility Planning Working Group and report out to GMAC on an agreed upon cadence.

Section 12
Workforce, Economic, and Health Benefits

This section provides an assessment of how the Company's proposed Future Grid investments contribute to workforce, economic development, health, and climate benefits.

Key Take-Aways

- The Future Grid Plan will bring significant environmental, climate, health benefits and economic benefits at the state level.
- The Future Grid Plan investments will result in increased economic activity on the order of $1.4 billion and create an additional 11,000 jobs throughout the Commonwealth by 2030.
- The Company already pays nearly $240 million in state and local property taxes, and the additional infrastructure build-out under the Plan will lead to incremental tax revenue, including for local communities.
- The Company has a multi-pronged workforce development program focused on EJCs that will provide a talent pipeline from these communities.

12.0 Workforce, Economic, And Health Benefits

12.1 Overview of Key Impact Areas

The network investments detailed in this plan, supported by technology and programs, will enable multiple benefits for the Company's customers and the Commonwealth, including health, economic and workforce, while driving down greenhouse gas emissions to meet Massachusetts' net zero targets. The benefits identified from executing this Plan were based on an assessment by Energy and Environmental Economics (E3)[1] and a jobs and economic impact analysis conducted by West Monroe using the BEA's RIMS II Multipliers model to estimate levels of economic activity and job creation, which found that up to an additional $1.4 billion of economic activity and 11,000 full a part-time jobs could be created over the first five years of this plan.

As illustrated in Exhibit 12.1, and detailed in Sections 6 and 7, the investments in network infrastructure, technology and platforms, and customer programs deliver both direct and indirect benefits, the scope, scale and timing of which is predicated on customer demand for and adoption of clean energy technologies and the pace at which the Company can execute this Plan. This includes being able to attract, hire, and retain the talent necessary to construct, operate, and maintain this smarter, stronger and cleaner energy system. In this section, the Company provides an overview of its workforce development program strategy, efforts to date, and plans for the future, including a proposed program to accelerate the training and hiring of a skilled workforce from the communities we serve.

[1] https://www.ethree.com/

Exhibit 12.1. Benefits Enabled by ESMP Investments

		Benefits									
		Reduced GHG Emissions & Climate Change Mitigation	Improved Health from Reducing Air Pollutants	Economic Development and Workforce Impacts	Grid Reliability and Resilience	Safety	Integration of DERs	Transportation & Building Electrification	Avoided Renewable Energy Curtailment	Mitigation of Land Use Impacts	Mitigation of Customer Bill Impacts
Network Infrastructure	Substation & Feeder Upgrades	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Technology Platforms & Initiatives	Network Management Comms	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Security	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Asset Planning, Management, & Workforce Execution	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Data	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Metering & Billing Systems	✓	✓	✓		✓	✓	✓			✓
	Customer Portals			✓			✓				✓
Customer Programs	Energy Efficiency, Demand Response, & Heating Electrification	✓	✓	✓				✓		✓	✓
	Clean Transportation	✓	✓	✓			✓	✓	✓		
	Non-Wires Alternatives	✓	✓	✓	✓		✓		✓		✓
	Resilient Neighborhoods	✓	✓	✓	✓		✓			✓	
	Time-Varying Rates	✓	✓				✓	✓			✓

12.2 Jobs Training and Impacts to Disadvantaged Communities

Across the Commonwealth, in both the electric and gas business, the Company directly employed approximately 6,500 employees during the last fiscal year. These direct jobs support the energy networks as they exist today. To build the electric distribution network proposed within this Plan, additional employees will be needed in sectors directly associated with the construction and operation of electrical infrastructure.

Across several recent analyses and plans, including those commissioned by the Commonwealth, projections indicate that there will be significant growth in employment needs in the electric sector:

- In the **Commonwealth's 2050 Decarbonization Roadmap Study**[2] projections indicate approximately 10,000 net electric transmission and distribution jobs in 2040 and 18,000 net jobs in this sector will be needed by 2050 to deliver on the "All Options" pathway.
- **MassCEC's Workforce Needs Assessment**[3] projected that statewide, the transmission and distribution sub-sector would need to more than double its clean energy FTE count between 2022 and 2030, growing 137% from 2,760 to 6,554 FTEs. These workers will be needed to implement the primary investments in the electrical network envisioned by the ESMP in addition to construction laborers and other support functions across the state.
- Under the **Commonwealth's CECP for 2025 and 2030[4]**, the electricity sector is projected to be the largest source of energy employment growth, adding 10,700 net jobs by 2030 and 34,300 net jobs by 2050 from the 2019 baseline. Of the 10,700 net jobs added to the electricity sector by 2030 in this projection, most added jobs are in the construction industry. Between 2019 and 2030, the construction sector is estimated to add 5,200 construction jobs, or 48% of the net employment gains for the sector.

These studies reinforce the estimates made for this Plan using the BEA's RIMS II Multipliers, which estimated that for the period 2025 – 2029 approximately 11,000 full- and part-time jobs would result from the proposed investments and approximately 22,500 full- and part-time jobs for the ten-year period of 2025 – 2034. This calculation is further discussed in Section 12.4.

These various estimates all point to the growth of employment associated with the energy transition and in particular, electric networks. Building the grid of the future will require significant growth in construction employment and associated sectors, supported by engineering, IT, and support functions. Jobs will also be created in other energy subsectors as additional growth is enabled in transportation electrification, building electrification, renewable energy, and ESS through additional capacity.

Identifying, engaging, and training the diverse talent necessary to support the investments to be made in the next five and ten years will require significant effort on the part of the Company, and more broadly throughout the clean energy economy. The Company has engaged in a robust strategic workforce development effort that will enable us to identify and develop talent to support our proposed investments, particularly from populations that are underrepresented in our current workforce, as described in Section 12.3. The jobs created through the Plan will be a mix of temporary and permanent jobs, and include union, non-union, and management roles. Section 7.3 also discusses how the Company considered the role that labor resource constraints may play in this plan.

Section 6 of the Plan describes the 5- and 10-year planning solutions for each sub-region, and Section 7 details the specific 5-year investment summary. Significant Plan-specific expenditures begin in 2025, ramp up over a five-year period, and continue at a significant level through 2034. Different job roles will be required at different times through 2034 to support the implementation of the Plan investments. For example, in the earlier phase of the planning window, more resources may be needed in planning, procuring, and engineering functions as designs are developed for infrastructure buildout. While the planning and design function ramps up in the earlier phase of the planning window, the need for additional construction support will continue through the 2034 period. While construction roles will likely be of shorter duration to support build out of the network in the first five and ten years of the plan, there will also then be a need for additional job roles to maintain and operate the network, including those in communications and information technologies, computer science, and data analytics.

[2] Economic and Health Impacts Report: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study, December 2020, Figure 7 https://www.mass.gov/doc/economics-and-health-impacts-report/download
[3] Powering the Future: A Massachusetts Clean Energy Workforce Needs Assessment, July 2023, Page 23, Figure 3. https://www.masscec.com/resources/massachusetts-clean-energy-workforce-needs-assessment
[4] CECP, Appendix D https://www.mass.gov/doc/appendices-to-the-clean-energy-and-climate-plan-for-2025-and-2030/download

Complementing the job roles required to build and operate the electric network will be job roles that help customers manage energy use and electrify end uses. The recent Mass Save Three-Year Energy Efficiency Plan for 2022 – 2024[5] can serve as a model for ways that the programs can engage in workforce development efforts, including leveraging relationships with Statewide organizations like MassCEC's Workforce Development programs in addition to efforts by the Program Administrators to directly influence the development of the energy efficiency and electrification workforce.

12.3 Workforce Training (with Action Plans) – Barriers for Building the Workforce Needed to Build and Operate the Grid of the Future

Background

A 2021 NASEO survey[6] shows that the U.S. energy sector has below-average representation of Black, Hispanic, and Latino, and women workers, and high rates of union members with low diversity representation. Specifically, the survey shows that just 8% of energy workers are Black compared to a 12% average across the national workforce. Similarly, Hispanic, or Latino individuals comprise 16% of energy workers yet represent 18% of the national workforce. Only 25% of energy workers are women despite comprising 47% of the national workforce. On the other hand, union membership in the energy sector is 11%, while the national average is a mere 6%.

The energy sector in the Commonwealth experiences similar disparities among the diversity of energy workforce. In addition, a recently released study[7] found that Massachusetts has the 6th biggest wealth gap[8] by race in the U.S. Addressing these disparities in Massachusetts will take the work of many across a variety of sectors and the Company is committed to taking action through its comprehensive Workforce Development (WFD) Strategy which has the potential to change the lives of many, especially those who obtain full-time employment with the Company or an affiliated vendor or contract partner. This will have a ripple effect on their families, and the communities where they reside.

Strategic workforce development strategy overview

The Company's New England WFD Strategy[9] is a comprehensive, strategic plan to address the Company's workplace skills and diversity gap. The strategy will position the Company to increase the skills and diversity of its workforce by sourcing talent from all the communities it serves, while creating generational wealth in these same communities. At its core, our WFD Strategy will address gaps in how the Company cultivates talent representing diverse backgrounds by employing four strategic programs we are currently piloting:

- **Energy Infrastructure Academy** prepares work-ready adults for entry level to mid-level roles within the Company's unionized workforce. The Company has partnered with Franklin Cummings Tech, Training Resources of America, Inc., Community Work Services, and

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[5] Massachusetts Joint Statewide Electric and Gas Three-Year Energy Efficiency Plan, 2022 – 2024. https://ma-eeac.org/wp-content/uploads/Exhibit-1-Three-Year-Plan-2022-2024-11-1-21-w-App-1.pdf

[6] NASEO, 2021. Diversity in the U.S. Energy Workforce: Data Findings to Inform State Energy, Climate, and Workforce Development Policies and Programs. https://www.naseo.org/data/sites/1/documents/publications/Workforce%20Diversity%20Data%20Findings%20MASTER%20Final42.pdf

[7] Boston Globe. Mass. has sixth-highest rate of Income Inequality, September 24, 2016. https://www.bostonglobe.com/metro/2016/09/20/massachusetts-has-highest-rate-income-inequality/MZFDqNcJJh8hJLqqd3zvFL/story.html

[8] https://thisweekinworcester.com/ma-6th-biggest-wealth-gap-race-012522/

[9] National Grid New England Strategic Workforce Development https://www.nationalgridus.com/News/2023/04/National-Grid-Launches-Multi-Pronged-Workforce-Development-and-Scholarship-Program-to-Increase-Diversity-of-its-Massachusetts-Labor-Force-/

STRIVE Boston to provide professional training for people interested in working in the energy industry. This academy, which launched in March 2023, holds classes in Boston and Worcester and provides nearly 200 hours of instruction to develop a combination of technical skills, soft skills, three weeks of hands-on job experience with Company employees, networking, mentorship, and more in preparation for full-time union role opportunities in an earn-while-you-learn on-the-job training. Trainees learn about and are trained in the Company's electric and gas operations, and project planning and construction. Trainees who successfully complete the academy are encouraged to apply for full-time positions within the company or a vendor partner and are supported in that effort. To date, 15 graduates have been hired.

- **Clean Energy Careers Academy** is and 8 week program for college and university students. The Company has partnered with Northeastern University, Franklin Cummings Tech, and UMass-Boston for this academy. Participating students receive mentorship from current employees and engage with the energy and utilities field, receive professional development opportunities, and create connections that can lead to future internships, co-ops, and full-time employment within the Company. As part of this long-term partnership, the Company announced a $300,000 Clean Energy Scholars Scholarship to support and encourage more students from historically underrepresented communities to pursue and persist in obtaining Engineering and Craft and Trades related degrees and certificates. Each partner is receiving $100,000 in the first year of the partnership, with scholarship funds to continue for the duration of the partnership. Students can apply for the scholarship through their respective institution.
- **Clean Energy Tech Academy** is for High School and Vocational Technical (VocTech) students. This academy enables students to explore energy field careers and topics and learn about career industry opportunities while enabling their professional development. The tech academies are being conducted at the Boston Green Academy, Dearborn STEM Academy and Madison Park Vocational Technical High School, and the Worcester Vocational Technical High School. Students who successfully complete the 3 to 5-day academy receive a certificate from the Clean Energy Tech Academy and career pathway experiences from mentors at the Company.
- **Clean Energy STEM Academy** is designed for middle school students. The Company mentors and introduces students to the energy industry and provides hands-on activities in STEM education. Boston Green Academy, Dearborn STEM Academy in Roxbury and Forest Grove Middle School in Worcester are program partners. Students who successfully complete the 3- to 5-day program receive a certificate from the Clean Energy STEM Academy.

Through these academies, over the next five years, the Company aims to achieve three main goals: (1) To implement the five-year workforce development strategy driven by forecasted workforce planning business needs; (2) Test and validate Company strategy, with a focus on craft and trades; and (3) Engage employee-led groups and our community/education partners and collaborators to ensure their input, lessons learned, best practices, and expertise are continuously incorporated.

These programs are supplemented by talent development-supporting pathways, including:

- **Clean Energy Scholars Program** – The Company offers scholarships to individuals representing underrepresented groups to help defray the cost of obtaining a certificate or undergraduate degree.
- **Mentorship Program** – Individuals are matched with Company employees or vendor/contract partner employees, who will serve as a support system.
- **Internships / Co-ops** – The Company offers paid internships and co-ops to help students gain hands-on, real-world business experience and earn while they learn.

- **Apprenticeship / Energy Infrastructure Academy** – Attract the unemployed and underemployed through outreach and engagement. Offer industry-specific training that allows the Company's to hire from a diverse pool of qualified candidates with industry-specific knowledge.
- **Company Site Visits** – Visit Company facilities and walk in the shoes of the Company's engineers, field employees, and others.
- **School Roundtables / Class Projects** – Employees engage students in classroom discussions about the energy industry and how the Company is transforming its electricity and gas networks with smarter, cleaner, and more resilient energy solutions.
- **Other Support** – Individuals receive support for resume writing, interviewing, assessments, exams, and navigation through the corporate environment. They are placed in a cohort and introduced to employee resource groups (ERGs) and similar organizations.

NE Clean Energy Line Worker Certificate Program

MassCEC's July 2023 Report, "Powering the Future: A Massachusetts Clean Energy Workforce Needs Assessment" found that the Commonwealth will need over 134,000 clean energy jobs by 2030 to meet the state's climate targets, growing from approximately 104,000 FTE jobs in 2022.[10] The Company's clean energy academies can support this effort. The clean energy academies place a priority on academic, vocational skills development and on-the-job training opportunities necessary for entry into clean energy jobs at the Company and our vendor partners.

A specific identified area of need is line workers. The electric utility industry is facing a critical shortage of qualified workers, specifically line mechanics and technicians, due to many workers retiring. Yet those in historically underrepresented communities experience barriers accessing programs that provide line worker training (e.g., training cost and transportation). The Company's Strategic WFD team proposes to develop a **Clean Energy Line Worker Certificate** program in response to the demand for OH electric line workers throughout Massachusetts. This Certificate program will be an expansion of the Company's Energy Infrastructure Academy for work-ready adults.

To build the Energy Infrastructure Academy Clean Energy Line Worker Certificate program, the Company proposes to partner with 2-year academic and training organizations that could include: Bristol Community College, Job Corp; Quinsigamond Community College in Worcester, Massachusetts, and Franklin Cummings Tech; PowerCorps Boston; Bunker Hill Community College; and Roxbury Community College in Boston.

This training program would be designed for those who want to enter the workforce immediately following graduation. Graduates of the Energy Infrastructure Academy have been very successful in securing positions with the Company and vendor partners, with 15 graduates securing full-time positions to date.

The proposed Clean Energy Line Worker Certificate program would include courses aligned with Electrical Construction and Maintenance requirements. The certificate program would include AC/DC electricity courses, technical math courses, OSHA 10 safety and CPR courses, commercial driver's licenses (CDL) permit test preparation, electrical wiring courses, industry specific electric power courses, and agility training.

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[10] Powering the Future: A Massachusetts Clean Energy Workforce Needs Assessment, July 2023. https://www.masscec.com/resources/massachusetts-clean-energy-workforce-needs-assessment

Clean Energy Re-Entry Program

The Company understands that through infrastructure development, a positive impact can be made on the Company’s communities. As part of a clean energy transition strategy that is just, fair, and equitable, individuals from within the Company’s communities who might not have considered the energy sector as a career choice need to be identified, recruited and trained.

Last year over 2,000 people were released from state prisons. These individuals are known as returning citizens. Returning citizens are considered hidden workers;[11] a group of people who are eager to work and possess—or could develop—skills sought for in the energy sector. According to Accenture’s research, companies that hire hidden workers were 36% less likely to face talent and skills shortages compared to companies that do not.

Governor Healey’s administration is committed to reducing recidivism and has included over $10M in funding[12] to bolster re-entry services. Leveraging the Company‘s alignment with the Governor’s agenda, as an industry partner, the Company proposes developing a Clean Energy Re-Entry Program and partnering with organizations such as STRIVE Boston, PowerCorps Boston, National Urban League, and BlocPower who already work with this population to identify individuals who have ‘nonviolent’ offenses and would be good candidates.

To be accepted into the Clean Energy Re-Entry Program, individuals would be approximately nine months away from release or completed their incarceration and demonstrate a willingness to work. Through the Clean Energy Re-Entry Program, trainees will receive work readiness and skills training to help prepare them for meaningful employment upon release. The program’s 4-weeks paid on-site training will allow the participant to gain skills that could lead to full-time employment opportunities in energy efficiency. The Company recommends piloting this program in January 2024 with BlocPower with an eye to expand the program upon demonstrating success.

Funding Opportunities

The NE Strategic WFD program has identified the funding opportunities shown in Exhibit 12.2 to help expand and scale the Company's WFD efforts.

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[11] https://www.accenture.com/us-en/insights/consulting/finding-hidden-talent
[12] https://www.wbur.org/news/2023/04/24/massachusetts-prisoner-reentry-classes-funding

Exhibit 12.2: WFD Funding Opportunities

No.	Strategic WFD Initiatives Potential Funding Sources	Description	Amount	Duration	Status
1	(IIJA) Future Grid Project	A non-traditional utility capital infrastructure smart grid project with an emphasis on the deployment of innovative digital technology solutions that maximize the value of DERs (*e.g.*, solar, ES) for the benefit of the electric distribution system. This grant will help fund a portion of the Company's Workforce Development Energy Infrastructure Academy's 12-week training program costs and trainees' stipends for 4 cohorts X 15 students; 60 students / year.	$1.2M	Over 5 years	Applied March 2023; Award decision anticipated August 2023
2	(IIJA) Greener Grid Brayton Project	A collaboration with Bristol Community College National Offshore Wind Institute to develop a training program (curriculum and internships) focused on training line workers to support Offshore Wind industry.	$2M	Over 8 years	Applied May 2023; Award decision anticipated December 2023
3	UMass Boston Micro-credentialing program	A collaboration with UMass Boston to develop micro-credentialing courses for non-traditional students to provide another pathway for students to earn an undergraduate engineering degree and increase the number of diverse students into clean energy, engineering programs. Trainees will gain knowledge, skills, and competences, evidencing the same by certifying the learning outcomes of short-term learning experiences.	$3M	Over 8 years	Applied May 2023; Award decision anticipated December 2023
4	MassCEC Capacity Funding	A collaboration with Training Resources of America, as an industry partner, to build the capacity necessary to scale the Company's Energy Infrastructure Academy trainees in Worcester in skills needed for clean energy field roles.	$150K	1 year	Applied June 2023; Award decision anticipated September 2023

No.	Strategic WFD Initiatives Potential Funding Sources	Description	Amount	Duration	Status
5	MassCEC Clean Energy Intern Program	This program reimburses Industry Partners up to 90% of clean energy interns' labor costs for up to 12 weeks.	$50K	Annually	Ongoing
6	Commonwealth Corporation	Workforce competitiveness trust fund for workforce development training to meet the skill needs of businesses in high-demand occupations.	$25M	TBD	Future Opportunity
7	Massachusetts Clean Energy Center	This funding for re-entry pathways including green career training programs to support wind technology, clean homes, and workforce training programs in the clean energy industry.	$30M	TBD	Future Opportunity
8	Summer Jobs Program	This funding is for Summer Jobs program for At-Risk Youth (Youthworks) to subsidize wages and facilitate career development.	$16.2M	TBD	Future Opportunity
9	Career Technical Institutes	This program is for Career and Vocational Technical Institutes for workforce development training.	$15.4M	TBD	Future Opportunity

12.4 Location economic development impacts

The Company has organized the Massachusetts territory into six sub-regions, as discussed elsewhere in this plan. These are: Central, Merrimack Valley, North Shore, Southeast, South Shore, and Western. The operating districts are defined based on historical precedents (e.g., the Company's predecessor, company service areas, service area geography, operating voltages, substations, and/or distribution system design characteristics.) Each sub-region has unique conditions and circumstances, as discussed in Section 4, that have influenced the development of the distribution system. paired with the forecast demand in each sub-region largely dictate the economic impacts by sub-region.

Within these six sub-regions, 46 study areas were assessed for distribution network investments in the 5-year and 10-year timeframes and incremental system investments were identified in all six sub-regions, as discussed earlier in this plan Sections 6.5 through 6.10 and 7.0. The proposed investments are highest where there is greatest identified system need. Merrimack Valley, for example, has more existing available capacity relative to projected load growth than other sub-regions and so the same level of investment is not required to achieve the goals of the ESMP in that sub-region. These investments are planned across the Company's service area in all locations for the benefit of all customers and communities including those that are home to environmental justice populations.

The planned incremental investments have been scoped to meet the needs of forecasted demand and identified system needs. Therefore, economic impacts from those incremental investments will be highly dependent on the types of investments planned for a particular location in response to the identified need. For example, investments in system capacity in more densely populated areas may enable more economic development due to the higher level of economic activity already occurring in those areas and anticipated needs of growing load. In general, the increased buildout of capacity on the system will allow for increased economic development that is anticipated by the load that will be coming online in the future, as anticipated by the demand forecasts. Refer to Sections 4.3.3, 4.4.3, 4.5.3, 4.6.3, 4.7.3, and 4.8.3 for additional discussion of economic development in each sub-region.

Given the infrastructure investments across the six sub-regions and across the service territory, direct economic impacts from the construction of the proposed infrastructure can be expected to occur broadly. Significant expenditures will go towards construction, electrical equipment manufacturers and suppliers, and other supporting industries that provide the materials, skilled labor, and supporting services to enable these investments. Beyond the direct impacts of the construction of electrical infrastructure, the buildout of the network will further enable economic growth in each sub-region by providing sufficient capacity to meet the forecast demand.

Some economic impacts occurring directly from ESMP infrastructure investments will be highly local while others will occur in a more distributed fashion. For example, direct construction expenditures will have a portion of their impact in the region where the construction activities occur as local labor is sourced, and some materials are purchased locally. Those wages paid to local personnel will then pass through to other economic sectors, both locally and more broadly. Increased construction activities and infrastructure may have positive revenue impacts for communities, as incremental property tax payments are made to local municipalities that host new infrastructure projects.

Other expenditures associated with infrastructure investments such as materials purchases may have different locational impacts. Some portion of those expenditures will be made in the local, state, or regional economy depending on supply chains and sourcing opportunities. Other categories of needed materials and supplies like transformers would occur on a much broader procurement base, with sourcing on a national or international scale.

Customer program investments that the Company currently implements, and that are planned to continue as discussed in Section 6.1, are typically broad-based offerings that are accessible to customers across the service territory and the State. The economic impact of these initiatives will therefore be similarly broad-based and rely on a variety of supporting businesses and local employment including program implementation, support personnel, and materials suppliers. For example, the Mass Save EE and electrification programs support a broad workforce including energy auditors, HVAC installers, program operation support, and weatherization contractors. The clean energy workforce will continue to grow in importance with continued investment through the ESMP.

In order to highlight the economic benefits of the ESMP, the Company has used the Bureau of Economic Analysis ("BEA") Regional Input-Output Modeling System II ("RIMS II") approach to estimate the economic impact based on a capital multiplier specific to the region. The BEA is a United States government agency responsible for the creation of official economic statistics, which provide a comprehensive and up-to-date picture of the United States economy to assist businesses, policy makers, and citizens. The economic impact calculation was based on regional economy-wide impacts of the BEA RIMS II approach.

The RIMS II methodology takes as input the annual expenditure of program capital for the Company's base spending, active regulatory investments, and ESMP proposed investments[13] multiplied by a final demand output multiplier to estimate economic impact.[14] Based on this modelling for the periods 2025 – 2029 and 2030 - 2034, the Company anticipates that the capital investments outlined in the Section 7.1 will yield considerable economic impact, approximately $1.4 billion of incremental output from 2025 – 2029, and for the ten-year period of 2025 – 2034 approximately $2.9 billion of incremental output.

Employment impacts were similarly estimated for the proposed level of ESMP investments using

[13] Estimated base spending, approved in-progress capital programs, and proposed ESMP investments. Impacts from NEP transmission are not modeled here.
[14] The RIMS II category is "Electric power generation, transmission, and distribution" and the Type I final demand output multiplier is 1.244 for Massachusetts.

RIMS II Type I Multipliers.[15] As noted earlier in Section 12.2, for the period 2025 – 2029 approximately 11,000 full- and part-time jobs would result from the proposed investments and approximately 22,500 full- and part-time jobs for the ten-year period of 2025 – 2034. The results of this modeling are summarized below in Exhibit 12.3, with further detail on the RIMS II modeling approach below.[16]

Exhibit 12.3. Economic and Employment Impacts of ESMP

Period	Economic Impact of Final Demand, Incremental Benefit ($M)	Employment Impact of Final Demand, Incremental full- and part-time Jobs (#)
2025 – 2029	$1,394	10,958
2030 – 2034	$1,468	11,542
2025 – 2034	$2,862	22,500

The RIMS II Type I multipliers estimate job creation by employing economic multipliers that take into account the direct and indirect employment impacts of economic activity. For direct jobs, the model forecasts the positions directly created as a result of a specific project or investment, like those at a newly built substation. For indirect jobs, the model takes into account the positions created in related industries due to the initial investment, such as third-party entities supplying materials or services to the construction of the substation.[17] The direct and indirect impacts of these calculations reflect a broad perspective of the impact of the direct economic activity and the associated rounds of spending in the economy associated with these investments. It is important to note that the job creation figures calculated here include both full-time and part-time positions and are not equivalent to FTE positions.

According to the RIMS II model, the number of jobs created represents the total change in the job counts across all industries for every additional $1 million of output delivered to final demand. These job creation figures are calculated by multiplying the annual investment by the respective industry's employment ratio at the state level, in this case the Electric Power Generation, Transmission, and Distribution category.

12.5 Health Benefits

The investments made in the distribution network through the ESMP, in addition to the customer programs that are in place today and continuing in the future, will enable a variety of environmental and climate benefits that will lead to improved health benefits and outcomes. Benefits will be realized at local and state scales through emissions reductions, improvements in building air quality, and through positive climate impacts that will occur within and beyond the state's borders. Building out the electric network to enable increased electrification, reinforcing it, and providing opportunities for EE and increased adoption of renewable energy will provide health benefits for all customers, in particular those within EJCs that are particularly impacted by negative health effects from poor air quality.[18] [19]

[15] The RIMS II category is "Electric power generation, transmission, and distribution" and the Type I Indirect Jobs Multiplier (Jobs in all industries per $1M of output delivered to final demand) is 1.920 for Massachusetts. Note that these are full and part time jobs, not FTEs.
[16] Refer to the BEA website for further information on RIMS II multipliers: https://apps.bea.gov/regional/rims/rimsii/
[17] A third category of impact is called "Induced" Impact. This impact is not modeled in the RIMS II Type I multipliers. Induced Impact is the change in economic activity resulting from the changes in spending by workers whose earnings are affected by a final-demand change. For example, spending at a restaurant by a construction worker employed to build a substation could be captured by an Induced Impact.
[18] https://www.epa.gov/air-research/research-health-effects-air-pollution
[19] https://www.lung.org/research/sota/health-risks

Building out the electric grid to meet anticipated demand from future load, including from the adoption of electrification of heat and transportation, will also provide increased capacity for renewable energy on the grid. Reductions in GHG emissions and air pollutants are a result of a cleaner electricity supply from increased penetration of renewable energy enabled by capacity expansion and grid modernization. Specifically, higher integration of renewables and zero or low carbon DERs will result in less reliance on fossil fuel generation that emits CO_2 and methane (CH_4) that contribute to climate change as well as criteria air pollutants, such as sulfur oxides (SO_X), nitrogen oxides (NO_X), and fine particulate matter ($PM_{2.5}$). Criteria air pollutants, such as SO_x, NO_x, and $PM_{2.5}$, have well documented impacts on respiratory and cardiac disease.[20] [21] Reducing air pollutants decreases the risk of asthma, lung cancer, and heart attacks, improving overall public health. While improved ambient outdoor air quality has positive health impacts for all, it can especially benefit LMI, EJ, and other vulnerable communities who may face either high concentrations of ambient air pollutants or greater sensitivity to their impacts. Poor air quality can disproportionately impact sensitive populations such as those with medical conditions like respiratory problems, children, the elderly, and pregnant women.

Non-energy impacts from EE and electrification measures including health benefits, thermal comfort, and noise reduction, are well-studied and documented within the triennial energy efficiency plans implemented by the Company and the other Mass Save program administrators.[22]

Electrification of transport can also result directly in reduced pollution from internal combustion engine vehicles, and result in further ambient air quality improvements and health benefits as the electric supply decarbonizes. Emissions impacts can also be highly localized from existing transportation and can have differential impacts depending on the location and intensity of the emissions. For example, in more densely populated urban areas vehicle density can be higher leading to higher emissions concentrations and air pollution impacts. Those emissions impacts can disproportionately impact EJCs. Increased adoption of EVs, including by fleets, enabled by additional system capacity and programmatic offerings, can result in reduced local emissions including particulates and ozone that impact populations more heavily burdened by negative health and climate impacts.[23] [24]

Reducing GHG emissions, decreases the public's risk of exposure to health-related impacts caused by climate change.[25] Climate change increases the likelihood of extreme weather events and heat waves that can exacerbate pre-existing health conditions, leading to injuries, illness, and premature deaths. Heat and natural disasters can also lead to trauma and higher levels of anxiety and depression, potentially worsening the mental health crisis. The Company has outlined a framework for assessing and prioritizing resiliency in Section 10 which seeks to mitigate climate change, reducing the possibility of these public health outcomes.

[20] https://www.niehs.nih.gov/health/topics/agents/air-pollution/index.cfm
[21] https://www.epa.gov/system/files/documents/2023-01/Estimating%20PM2.5-%20and%20Ozone-Attributable%20Health%20Benefits%20TSD_0.pdf
[22] https://ma-eeac.org/wp-content/uploads/Exhibit-1-Three-Year-Plan-2022-2024-11-1-21-w-App-1.pdf
[23] https://www.lung.org/clean-air/electric-vehicle-report/driving-to-clean-air
[24] https://www.epa.gov/mobile-source-pollution/environmental-justice-and-transportation
[25] https://www.niehs.nih.gov/research/programs/climatechange/health_impacts/asthma/index.cfm

Section 13
Conclusion

This section describes next steps for the Future Grid Plan, including a discussion of reporting and metrics.

Key Take-Aways

- The Company believes that input from stakeholders and GMAC will result in a better plan for the Company and the communities we serve. To get that input, the Company will hold stakeholder workshops in the fall of 2023.
- The Company proposes creating a new Community Engagement Stakeholder Advisory Group to develop a Community Engagement Framework that can be applied to Future Grid infrastructure projects before they are brought before the Energy Facilities Siting Board.
- The Company's January filing of the Future Grid Plan with the Department will reflect GMAC and other stakeholder feedback and include a detailed customer benefit analysis per Department guidance.
- So that the Company can demonstrate the delivery of the investments included within the Future Grid and associated benefits, the EDCs will develop key metrics based upon the extensive set of existing performance metrics relevant to ESMP objectives already in place with the Department and EDCs.

13.0 Conclusion

13.1 Next Steps

A smarter, stronger, and cleaner energy future for the Commonwealth rests upon developing comprehensive, inclusive, and flexible plans that upgrade today's electric grid rapidly and at significant scale. The Company has crafted the Company's Future Grid Plan with a realistic and detailed plan established for the next five and ten years, and a vision for the steps that will be needed to meet decarbonization targets by 2050.

In the period following the submission of the Company's Future Grid Plan to the GMAC, the Company will support all aspects of the GMAC review process, including provision of any requested clarification or background information to inform GMAC of findings and recommendations.

The Company is committed to at least two stakeholder workshops in the fall of 2023 as part of the ESMP filing process. The Company believes, as a rule, that the public engagement process should be robust and that proactively soliciting feedback is critical. In addition to the initial stakeholder workshops, to further inform the Company's engagement efforts around proposed projects from Section 6, the Company is proposing the development of the CESAG. The goal of the new advisory group is to develop a Community Engagement Framework that can be applied to Section 6 ESMP projects before they are brought before the DPU and the EFSB. The composition of the CESAG would be agreed upon by members of the GMAC, and recommendations from the fall ESMP workshops. The CESAG is described in Section 3.

As discussed below, the Company, in collaboration with other EDCs, will propose ESMP metrics and a reporting template for stakeholder review and comment prior to submitting the ESMP to the Department in January. These metrics and reporting template will be designed to support transparency and accommodate midterm modifications based on GMAC and stakeholder feedback prior to submission of the Company's next ESMP in 2028.

Finally, the Company is working to refine its customer benefit analysis to include a quantitative, where available, and qualitative net benefits assessment, including a quantification of the greenhouse gas emissions reductions resulting from the Company's investments included in the ESMP. This net benefits assessment will be included in the Company's filing with the Department in January.

13.2 Process to Support Updates to ESMP Throughout the 5-Year Cycle

The 2022 Climate Act, 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 to 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 biannual 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 biannual reports and an assessment and recommendation from the Company or joint EDC's regarding elements of the ESMP or specific investments. The EDCs expect this review cycle will help refine and improve the ESMP and the ability to support 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 fully 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 in 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 the Company 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 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
- Electric Vehicles
- AMI / Time Varying Rates
- Interconnection Timelines

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.

In addition to including existing metrics into the ESMP reporting template as described above, the EDCs are working to develop new ESMP-specific metrics designed to ensure full transparency with respect to all ESMP expected outcomes. The EDCs are planning the following process to develop a full metric recommendation for inclusion in each Company's ESMP filing to the Department in January.

- EDCs propose ESMP metrics (new and existing/proposed) by October 1, 2023;
- Conduct collaborative stakeholder sessions to gather feedback on EDC proposed metrics;
- Final recommendation of ESMP metrics, incorporating stakeholder feedback, is presented to the Department in January.

The EDCs proposes to deliver 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:

- Be susceptible to objective and transparent measurement;
- Have an established baseline against which performance can be measured;
- Measure "performance" that is within the EDC's control; and
- 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 the Company's 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. 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. Infrastructure metrics track a Company's deployment and investments of ESMP projects and technologies. Examples of existing infrastructure metrics include the number of AMI meters installed, number of feeder monitors installed, and milestones for approved technologies and projects.

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 expect an ongoing collaboration with the Grid Modernization Advisory Council and other stakeholders throughout the ESMP plan period with discussion and updates supported through the biannual reporting. Exhibit 13.1 below summarizes the categories of metrics the EDCs currently are working to develop.

Exhibit 13.1 Metrics Categories in Development by EDCs

Category	Description
Implementation	Delivery of ESMP investments relative to established milestones
Resiliency	Customers benefitting from resiliency investment and improvements in relevant outage statistics[1]
Electrification and DER Hosting Capacity	Amount of Electrification and DER capacity enabled on the distribution system
Use of DER as a Grid Asset	Amount of capacity enabling Grid Services and Flexible Load
Stakeholder Outreach	Specific engagements with stakeholders including those in EJ, disadvantaged, or underserved communities

The metrics categories above are expected to have specific metrics that are a combination of the existing metrics discussed above and new metrics created through a stakeholder engagement process related to developing the appropriate metrics for the ESMPs.

13.4 Process to Report to DPU and Joint Committee on Telecommunications, Utilities, and Energy

The EDCs expect an ongoing collaboration with the Grid Modernization Advisory Council throughout the ESMP plan period with discussion and updates supported through the biannual reporting. In addition to the GMAC, the biannual reports will be provided to the Telecommunications, Utilities, and Energy working group. As described in 13.2, the EDCs proposed a timeframe for the biannual reporting to be April 1 for the previous year January - December timeframe and October 1 for the current year January - June timeframe update. These timelines best align with many existing dockets and annual reporting timelines which will be leveraged and incorporated into the Company's overall biannual reporting efforts.

[1] Resiliency investments are core investments of the Company that are included in this plan to provide a complete view of the Company's investment plans.

Section 14
Appendix

This section includes a ESMP Stakeholder Engagement Table, Exhibits 1-5 and glossary.

14.0 Appendix

Exhibit 1: Glossary

Acronym	Term
2022 Climate Act	An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy
AARP	American Association of Retired Persons
ACC	Advanced Clean Car, as in California Advanced Clean Car Rule
ACC II	California's Advanced Clean Car II Rule
ACT	California's Advanced Clean Trucks Rule
ADMS	Advanced Distribution Management System
AGO	Attorney General's Office
AI	Artificial Intelligence
AMF	Advanced Metering Functionality
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
API	Application Programming Interface
APRS	Active Power Restoration Services
ARI	Active Resource Integration
BCA	Benefit Cost Analysis
BEA	Bureau of Economic Analysis
BEV	Battery Only Electric Vehicle
BNEF	Bloomberg New Energy Finance
BTM	Behind the Meter
C&I	Commercial and Industrial
CAGR	Compound Annual Growth Rate
CAIDI	Customer Average Interruption Duration Index
CAP	Community Action Program
CAPEX	Capital Expenditures
CCRT	Climate Change Risk Tool
CDL	Commercial Driver's License
CE 2.0	Clean Energy 2.0
CECP	Clean Energy Climate Plan
CIAC	Contribution in Aid of Construction
CIP	Capital Investment Project
CIS	Comprehensive Integration Services
CMI	Customer Minutes of Interruption
CO_2	Carbon Dioxide
COD	Commercial Operation Date
CSS System	Customer Information and Billing System
CVR	Conservation Voltage Reduction
Department, MDPU, DPU	Massachusetts Department of Public Utilities
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DOER	Massachusetts Department of Energy Resources
DPAM	Distribution Planning & Asset Management
DR	Demand Response
EDC	Electric Distribution Company
EE	Energy Efficiency
EEA	Executive Office of Energy and Environmental Affairs
EEI	Edison Electric Institute

EEP	Energy Efficiency Programs
EFD	Early Fault Detection
EFSB	Energy Facilities Siting Board
EH	Electrification of Heat
EHP	Electric Heat Pump
EHTM	Enhanced Hazard Tree Mitigation
EIA	Energy Information Administration
EJ	Environmental Justice
EJC	Environmental Justice Community
ELF	Electric Load Forecasting
EMS	Energy Management System
EOPs	Electronic Standards and Electric Operating Procedures
EoT	Electrification of Transportation
EPA	Environmental Protection Agency
EPC	Engineer Procure Construct
EPO	Energy Profiler Online
EPRI	Electric Power Research Institute
EPS	Electrical Power System
ERG	Employee Resource Group
ERO	Emergency Response Organization
ERP	Massachusetts Electric Emergency Response Plan
ES	Energy Storage
ESB	Enterprise Service Bus
ESMP	Electric Sector Modernization Plan
ESRI	Environmental System Research Institute
ESS	Energy Storage Systems
ETR	Estimated Time of Restoration
EV	Electric Vehicle
EVM	Enhanced Vegetation Management
EVSE	Electric Vehicle Supply Equipment
FAN	Field Area Network
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation and Service Restoration
FTE	Full Time Equivalent
FTM	Front of the Meter
Future of Gas Report	Role of Gas Distribution Companies in Achieving the Commonwealth’s Climate Goals Report
FY	Fiscal Year
GAPP	Generally Accepted Privacy Principles
GBC	Green Button Connect
GBD	Green Button Download My Data
GHG	Greenhouse Gas
GIS	Geographic Information System
GMAC	Grid Modernization Advisory Council
GMP	Grid Modernization Plan
GWSP	Global Warming Solutions Act
HAN	Home Area Network
HCA	Hosting Capacity Analysis
HDEV	Heavy Duty Electric Vehicle
HIPPA	Health Insurance Portability and Accountability Act
HVAC	Heating, Ventilation, And Air Conditioning
IaaS	Infrastructure as a Service
IAM	Institute of Asset Management

ICAP	Installed Capacity
ICCP	Inter-Control Center Communications Protocol
ICE	Interruption Cost Estimate
ICS	Incident Command System
IDS	Intrusion Detection Systems
IEEE	Institute of Electrical and Electronics Engineers
IEP	Integrated Energy Planning
IIJA	Infrastructure Investments and Job Act
IMP	Inspection and Maintenance Program
INOC	Integrated Network Operations Center
Interconnection Tariff	The Company's Standards for Interconnection of Distributed Generation, M.D.P.U. No. 1248
IoT	Internet Of Things
IPT	IP-Based Telephony
IRA	Inflation Reduction Act
IS	Information Services
ISA	Interconnection Service Agreement
ISO	Independent System Operator
ISO-NE	Independent System Operator – New England
IT	Information Technology
IT/OT	Information Technology/Operational Technology
ITSM	IT System Management
kV	Kilovolts
kW	Kilowatt
kWH	Kilowatt Hour
L1	Level One
L2	Level Two
LAN	Local Area Network
LBNL	Lawrence Berkeley National Laboratory
LDV	Light Duty Vehicle
LIDAR	Light Detection and Ranging Remote Sensing
LMI	Low to Moderate Income
LSP	Local System Plan
LVA	Locational Value Analysis
MA	Massachusetts
MA EEAC	Massachusetts Energy Efficiency Advisory Council
MassCEC	Massachusetts Clean Energy Center
MDMS	Meter Data Management System
MDS	Meter Data Services
MDV	Meter Data Management
MECO	Massachusetts Electric Company
MEO	Marketing, education and outreach
MEPA	Massachusetts Environmental Policy Act
MHDEV	Medium and Heavy Duty Electric Vehicles
MITS	Meter Issues Tracking System
ML	Machine Learning
MMTCO2e	Million Metric Tons of Carbon Dioxide
MPLS	Multi-Protocol Label Switching
MUD	Multi Unit Dwelling
MV/LV	Medium Voltage/Low Voltage
MVA	Megavolt Ampere
MVSR	Merrimack Valley Sub-Region
MW	Megawatt
NAC	Network Access Control

National Grid	National Grid
nCAP	National Grid's Customer Application Portal
NDA	Non-Disclosure Agreement
NEMA	Northeastern Massachusetts
NEP	New England Power
NERC	North American Electric Reliability Corporation
NGCC	National Grid Customer Council
NHTSA	National Highway Safety Traffic Administration
NIMS	National Incident Management System
NIST	National Institute of Standards and Technology
NLP	Natural Language Processing
NMPC	Niagara Mohawk Power Corporation
NPCC	North Power Coordinating Council
NPP	Non-Regulated Power Producer
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NWA	Non-Wires Alternative
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
OMS	Outage Management Systems
OSHA	Occupational Safety and Health Administration
OT	Operational Technology
PBX	Private Branch Exchange
PHEV	Plugin Hybrid Electric Vehicle
PSP	Provisional System Planning
PV	Photovoltaic
RCP	Representative Concentration Pathway
RIMS II	Regional Input Output Modeling System II
ROW	Right of Way
SAFe	Scaled Agile Framework
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency
SCADA	Supervisory Control and Data Acquisition
SDP	System Data Portal
SD-WAN	Software-Defined Wide-Area-Network
SEMA	Southeastern Massachusetts
SOAR	Security Orchestration Automation & Response
STEM	Science, Technology, Engineering, and Math
STIG	Secure Telecommunications Internet Gateway
TAC	Technical Assistance Center
The 2050 Roadmap	The Massachusetts 2050 Decarbonization Roadmap
the Alliance	North Shore Alliance for Economic Development
the Company	National Grid
TVR	Time-varying rates
V2G	Vehicle-to-Grid
V2H	Vehicle-to-Home
V2L	Vehicle-to-Load
V2X	Vehicle-to-Everything
VIO	Vehicles in Operation
VMT	Vehicle Miles Traveled
VPP	Virtual Power Plant
VVO	Volt/Volt-Amps Reactive Optimization
WACC	Weighted Average Cost of Capital
WAN	Wide Area Network

WCMA	Western Central Massachusetts
WFD	Workforce Development
WTAM	Workforce, Training and Asset Management
ZEV	Zero Emission Vehicle

Exhibit 2: Draft Equity and Environmental Justice Policy and Stakeholder Engagement Framework

nationalgrid

Draft Equity and Environmental Justice Policy and Stakeholder Engagement Framework

September 2023

nationalgrid

Draft Equity and Environmental Justice Policy and Stakeholder Engagement Framework

National Grid is sharing this draft equity and environmental justice framework for stakeholder feedback. It is our intention that this document and its implementation reflect the perspectives of the communities we serve and that host the energy infrastructure needed to provide safe and reliable service to our 1.3 million customers throughout the Commonwealth. This document is intended to articulate our commitments to centering equity and environmental justice, building on our existing outreach and engagement practices, and leveraging input from environmental justice stakeholders to date and recommendations included in recent studies and reports published by EEA and the Attorney General's Office.[1] This document is also intended to be a living document reflecting the Company's intent to evolve equity and environmental justice objectives and practices over time based on experience and feedback.

National Grid is working to enable net-zero by 2050 and doing so in a way that will deliver a smarter, stronger, cleaner and more equitable energy future for all our customers and communities. We recognize the critical need to combat climate change and drive down climate pollution and are committed to meeting the clean energy and equity goals established by the Commonwealth's Clean Energy and Climate Plan (CECP). In addition to enabling equitable access to safe and reliable energy service for the customers and communities we serve, we are also committed to supporting realization of technology, economic and environmental benefits of the clean energy transition in all communities. These principles are articulated in our Vision and Values and Responsible Business Charter.

National Grid is committed to working transparently and collaboratively with stakeholders and communities to support equity and inclusion in the clean energy transition. We have a team dedicated to conducting such outreach. We are committed to reviewing and enhancing our current engagement practices, with a focus on public involvement surrounding our major infrastructure projects, especially in environmental justice and low-income communities. We recognize that many customers in these communities face barriers to accessing clean energy solutions, managing their energy bills, and engaging meaningfully in the stakeholder processes that provide for input regarding energy infrastructure and programs in their communities.

Our Objectives

As we work to advance a clean energy transition that centers equity and environmental justice in collaboration with our regulators and stakeholders, we are focusing on two key tenets of equity.

Procedural equity is focused on providing stakeholders and communities impacted by energy projects and programs with the necessary information and opportunity to participate in stakeholder processes to inform project siting, development, and implementation.

Distributional equity is focused on ensuring that the clean energy transition supports the more equitable distribution of the benefits and burdens associated with the clean energy transition.

We are committed to integrating this focus across our business by:

- Increasing transparency and education about future infrastructure investment plans, including the need for investments and the benefits and impacts to a host community;
- Engaging early with stakeholders, including directly and via trusted community sources, and enhancing open communication that supports clear and timely information sharing, community feedback, and ongoing dialogue;
- Expanding our understanding of community concerns and priorities;
- Enhancing project and program outcomes by identifying opportunities to mitigate adverse impacts and support community and customer benefits;
- Reducing barriers to participation in customer programs that can benefit low-income customers and environmental justice populations;
- Partnering with our communities and local organizations in support of broader social, economic, and environmental progress;
- Directly supporting economic opportunity and advancement, including through the development of a local, diverse clean energy workforce and supply chain; and
- Monitoring and informing on our progress in supporting equity and environmental justice on a regular and transparent basis.

Operationalizing Equity and Environmental Justice

We recognize that fully integrating equity and environmental justice into our operations, planning, programs, and day-to-day business will require new efforts that build upon existing initiatives within the Company and full operationalization of equity and environmental justice through an intentional approach. We are actively working to build upon and learn from our existing efforts and create new processes and procedures needed to advance the intentions outlined above, and to develop the necessary training and resources for our employees. We are working to establish a cross-functional team with dedicated leadership and transformation expertise to ensure that key business areas are equipped to implement this framework. In addition, we are working to engage external perspectives to inform these organizational efforts.

These efforts will continue to build upon and be informed by multiple successful recent and ongoing efforts including:

- Processes and practices to mitigate environmental impacts of construction.
- Public outreach and stakeholder engagement via multiple channels and with translation where needed in support of obtaining all applicable project permits and approvals and addressing construction impacts.
- Launching our Indigenous Peoples Initiative, a 3-part program designed to strengthen the Company's relationships with Federally Recognized Tribes within our New England operating area while creating benefits for those Indigenous Communities[2];
- Consideration of input from environmental justice stakeholders in the design of our customer programs. For example, our Energy Efficiency Programs include specific goals for equity and service to environmental justice populations developed in collaboration with the energy efficiency Equity Working Group. Our Electric Vehicle programs include enhanced incentives

for residential customers in environmental justice populations and more direct support of fleet electrification to reduce local air pollution in response to stakeholder feedback.

- Our Grid for Good program establishes a framework for National Grid's social responsibility priorities in Massachusetts that focuses on three pillars: (1) workforce development and STEM education, (2) economic opportunity and social justice, and (3) clean energy and sustainability; all underpinned by a partnership model focused on delivering outcomes, with a focus on environmental justice and underrepresented communities.
- Our strategic workforce development program, launched earlier this year, provides education, training, and development opportunities for young people and adult learners from underrepresented communities throughout the Commonwealth in partnership with thirteen academic and community-based organizations.

Evaluating our Progress

National Grid intends this commitment be a living document, updated and modified based on stakeholder feedback and lessons learned through experience. We are committed to collaborating with stakeholders to inform future review and development of these efforts.

Exhibit 3: List of Stakeholder Organizations Engaged by National Grid on the ESMP

Through the ESMP process, National Grid has engaged with more than **320 individual stakeholders** representing more than **155 unique organizations, agencies, governmental entities, and groups** on various issues related to and aspects of the ESMP, including its purpose, development, implementation, deliverability, and impact:

State Agencies
Office of the Attorney General
Department of Energy Resources
Executive Office of Economic Development
Massachusetts Department of Transportation
Executive Office of Labor and Workforce Development
Executive Office of Energy and Environmental Affairs, Office of Environmental Justice & Equity
Office of Climate Innovation and Resilience
Municipalities
Town of Acton
Town of Adams
City of Amesbury
Town of Athol
Town of Auburn
Town of Ayer
Town of Bedford
Town of Belchertown
Town of Beverly
Town of Billerica
Town of Boxford
Town of Brimfield
City of Brockton
Town of Burlington
Town of Carlisle
Town of Charlton
Town of Cheshire
Town of Dudley
Town of Leicester
City of East Longmeadow
Town of Egremont
Town of Erving
City of Everett
City of Fall River
City of Gardner
City of Gloucester
Town of Goshen
Town of Granby
Town of Great Barrington
Town of Hampden
Town of Hancock
Town of Hardwick

Municipalities continued
Town of Harvard
Town of Lancaster
City of Leominster
City of Lowell
City of Lynn
City of Malden
Town of Manchester-By-The-Sea
City of Medford
City of Melrose
Town of Middleton
Town of Millbury
Town of Monson
Town of Monterey
Town of Nahant
City of Newburyport
Town of New Marlborough
Town of New Salem
City of North Adams
City of Northampton
Town of Oakham
Town of Orange
Town of Oxford
Town of Palmer
City of Peabody
Town of Pepperell
Town of Phillipston
North Reading
City of Revere
Town of Rowley
Town of Rutland
City of Salem
Town of Saugus
City of Somerville
Town of Spencer
Town of Stockbridge
Town of Sturbridge
Town of Sutton
Town of Swampscott
Town of Tewksbury
Town of Topsfield
City of Waltham
Town of Ware
Town of Warren
Town of Wellesley
Town of Westminster
Town of West Stockbridge
City of Weymouth
Town of Wilbraham
Town of Williamsburg
Town of Williamstown

Town of Wilmington
City of Worcester
Elected Officials
Members of the Massachusetts House of Representatives
Members of the Massachusetts Senate
Community and Nonprofit Organizations, including Environmental Justice, Environmental and Consumer Groups
Browning the Green Space
Environmental Justice Table
Conservation Law Foundation
AARP Massachusetts
Citizens for Citizens
MASSPIRG
Worcester Community Action Council
Clean Water Action
Regulatory Assistance Project
Energy and Technology Organizations and Convenors
Advanced Energy Group
New England Power Generators Association
New England Clean Energy Council
Labor Organizations
IBEW Second District
United Steelworkers Union 12033
United Steelworkers Union 12012-04
Utility Workers Union of America 369
Business Organizations
Associated Industries of Massachusetts
Bristol County Economic Development Consultants
Gloucester Economic Development & Industrial Corporation
Lowell Chamber of Commerce
Massachusetts Health and Hospital Association
Massachusetts Restaurant Association
Merrimack Valley Chamber of Commerce
Retailers Association of Massachusetts
Waltham Chamber of Commerce
Worcester Chamber of Commerce

Exhibit 4: Report on National Grid's Load Forecasting by the Brattle Group

A Review of National Grid's Load Forecasting Methodology

PREPARED BY
Sanem Sergici, Ph.D.

PREPARED FOR
National Grid

AUGUST 30, 2023

Brattle

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Executive Summary

Massachusetts is one of the leading states in the nation with its ambitious clean power targets with the goal to reach net zero by 2050. These goals were articulated in Massachusetts' 2050 Clean Energy and Climate Plan (CECP) and further strengthened with legislation in 2022, *An Act Driving Clean Energy and Offshore Wind* ("2022 Climate Act"). With that goal in mind, *the 2022 Climate Act,* directed each Massachusetts electric distribution company (EDC) to file an Electric Sector Modernization Plan (ESMP) that identifies upgrades to the distribution and transmission systems, where needed. These plans would be structured to meet the Commonwealth's climate and clean energy goals over three planning horizons: 1) a 5-year forecast, 2) 10-year forecast, and 3) a demand assessment through 2050. This requirement implies that the EDC's load forecasting framework plays a fundamental role for development of a robust ESMP.

National Grid asked me, Dr. Sanem Sergici of the Brattle Group, to provide my independent assessment of the Company's load forecasting framework used in the development of the ESMP. Based on my review of Company's load forecasting documents, numerous meetings with the Company's load forecasting subject matter experts and my experience with developing and reviewing similar analyses over the course of my 20-year consulting career, I find that:

- The Company's base load forecasting methodology, estimation of an econometric model, aligns well with the current utility load forecasting landscape. The Company's econometric models used to generate energy and peak demand forecasts are robust and have the desired statistical qualities such as strong goodness of fit, statistically significant coefficients and expected signs for the independent variables.
- The Company's approach to incorporate the impacts of DERs to the econometric forecasts aligns well with electric utility industry best practices. The Company incorporates DER impacts to the results from the econometric model forecasts, as modifiers. The impacts from energy efficiency, PV solar, electric vehicles, demand response, electric heat pumps, and energy storage are projected using information on Company plans and project queues; feedback from subject matter experts; and the Commonwealth's clean energy and climate policy goals.
- The Company allocates system-level DER impacts to the feeder level using robust, DER-specific allocation approaches. The feeder-level allocation is the most granular allocation applied to the system-wide projections and is aggregated up to the power supply area (PSA) level.

- The Company evaluates multiple scenarios concerning the pace of adoption of DERs, leading to Base, Low and High Cases for DERs incorporated into forecasts. The Company also conducts a thorough uncertainty analysis on the results of its econometric peak demand forecast.
- The Company relies on well-established practices to track the forecasting performance of its econometric models.

I. Introduction

Massachusetts is one of the leading states in the nation with its ambitious clean power targets with the goal to reach net zero by 2050. These goals were articulated in Massachusetts' *2050 Clean Energy and Climate Plan* (CECP) and further strengthened with legislation in 2022, *An Act Driving Clean Energy and Offshore Wind.* The latter is aimed at ensuring the grid has the capacity and flexibility to absorb all the variable renewable generation expected to come online and to reliably meet the demands of increased electrification of transportation and buildings. With that goal in mind, *An Act Driving Clean Energy and Offshore Wind* directed each Massachusetts electric distribution company (EDC) to file an Electric Sector Modernization Plan (ESMP) that identifies upgrades to the distribution and transmission systems, where needed. These plans would be structured to meet the Commonwealth's climate and clean energy goals over three planning horizons: 1) a 5-year forecast, 2) 10-year forecast, and 3) a demand assessment through 2050. National Grid's load forecasting framework plays a foundational role for development of a robust ESMP given the short-term and longer-term planning horizons involved, expected changes over these time periods, and the spatial nature of the planning effort.

Nature of the Engagement

National Grid has developed an ESMP to meet the requirements of this legislation in a way that builds upon their existing investments to enable a clean, reliable, and affordable future for its customers. The Company asked Dr. Sanem Sergici of The Brattle Group to provide her assessment of the load forecasts that form the foundation for the analyses developed in the ESMP. Specifically, National Grid asked Dr. Sergici to address the following issues:

1. Please summarize and describe Company's forecasting approach.
2. Please summarize and describe Company's DER allocation methods.

3. Does the Company's baseload econometric load forecasting methodology align with electric utility industry best practice?
4. Does the Company's load forecast methodology account for the impacts on electricity demand from energy efficiency, beneficial electrification, and other distributed energy resources/flexible resources (e.g., solar PV, energy storage, demand response) and align with electric utility industry best practice?
5. Has the Company accurately accounted for the Commonwealth's clean energy and climate policy goals in its load forecast and demand assessment?
6. Does the Company evaluate multiple scenarios concerning the pace of adoption of new technologies such as electric vehicles, heat pumps, and solar PV?
7. Is the Company's methodology for allocating system-level load growth to distinct planning areas of its network robust?
8. Does the Company regularly assess the accuracy of its forecasts and update its methods to avoid systematic over- or under-forecasting?

The remainder of this report is organized around these eight issues. To address the issues, I reviewed various load forecasting documents prepared by the Company's load forecasting experts and attended several meetings with the subject matter experts, including a full-day working session with the ESMP team. Throughout the review process, I had plenty of opportunities to ask questions and request additional information and materials that would allow me to develop a comprehensive understanding of the Company's load forecasting methods. In addition to reviewing the Company's load forecasting methodology, I was able to compare it to the methods utilized by other leading utilities across North America. While I was able to gain a comprehensive understanding of the Company's overall load forecasting method, I did not undertake a "quantitative" review of any of their forecasts, programming codes to develop their econometric models, DER allocations, and resulting forecasts. Therefore, my review will only be restricted to the Company's approach and the methods used to develop the load forecasts for the ESMP analyses.

Summary of Expert Qualifications

Dr. Sanem Sergici is a Brattle Principal and an energy economist with twenty years of consulting and energy research experience. Sanem's consulting practice is focused on understanding customer adoption of and response to innovative rate designs, distributed energy resources, and emerging technologies. She regularly assists her clients in matters related to rate design, electrification pathways, grid modernization investments, load forecasting, and resource planning. She led numerous studies in these areas that were instrumental in regulatory approvals of grid modernization investments and smart rate offerings for electricity customers. More recently, Dr. Sergici undertook several studies that explore the impact of electrification on grid investments and investigate the role of customer side pathways in meeting climate goals. She has filed testimony quantifying the potential benefits of AMI investments for a Pacific Northwest utility and authored a report titled, "Reviewing the Business Case and Cost Recovery for Grid Modernization Investments," that reviewed ten recently approved grid modernization projects, cost recovery mechanisms, and documents how grid modernization technologies have benefitted customers and utilities. Dr. Sergici's full resume and qualifications are provided in the Appendix.

Dr. Sergici regularly publishes in academic and industry journals and presents at industry events. She received her PhD in Applied Economics from Northeastern University in the fields of applied econometrics and industrial organization. She received her MA in Economics from Northeastern University, and BS in Economics from Middle East Technical University (METU), Ankara, Turkey.

II. Commentary on the Key Issues

1. Please summarize and describe Company's forecasting approach.

The Company employs an econometric modeling approach to generate forecasts of electric deliveries and peak demand for Massachusetts Electric Company and Nantucket Electric Company. The Company prepares monthly forecasts for the two Companies through 2034, and undertakes a demand assessment beyond 2034 through 2050.

To forecast total electric deliveries, the Company generates use-per-customer and customer count models for its residential, residential electric heating, and commercial customers (industrial models are specified directly as total deliveries). The product of the two forecasts yields total overall electric deliveries. The Company leverages historical and projected data on key regional economic drivers such as number of households and manufacturing employment to inform the customer count projections, and gross state product to project usage per customer. Results are weather-normalized by incorporating the ten-year average of heating degree days and cooling degree days into the regression models.

The peak demand forecasts are also developed econometrically. Two Company-level forecasts are developed for MECO and Nantucket, and three zone-level forecasts are developed for the portions of the Northeast, Southeast, and West Central Massachusetts load zones that are served by MECO and/or Nantucket. Each peak demand model is developed based on a “reconstituted” model of past load, which adds energy efficiency, PV solar, demand response, and energy storage impacts back into the historical energy dataset, and subtracts out the demand impact that beneficial electrification added in. Historic peaks are then regressed on this aggregate system energy. If energy alone is not a good statistical fit, the Company applies data on zone-specific economics to the regression. Weather-adjusted peaks are derived for 50/50, 90/10, and 95/5 scenarios.

The impacts of distributed energy resources (DERs) on total energy and peak demand are evaluated separately and are added as ex-post adjustments to the econometric forecasts. The Company considers impacts from energy efficiency, PV solar, electric vehicles, demand response, electric heat pumps, and energy storage in its final forecasts; the impacts of each are projected using information on company plans and project queues, feedback from subject matter experts, and state-level mandates or targets. DER impacts are incorporated as “modifiers” to the results from the electric delivery and peak demand econometric models.

2. Please summarize and describe the Company’s DER allocation methods.

The Company allocates system-level DER impacts to the feeder level using robust, DER-specific allocation approaches. The feeder-level allocation is the most granular allocation applied to the system-wide projections and is aggregated up to the power supply area (PSA) level for PSA projections.

System-level **energy efficiency (EE) savings** are based on the Company’s 3-year EE plan (approved by the Massachusetts Department of Public Utilities) in the short term, and are projected long term assuming that the cumulative value of persistent EE savings will grow at a slower rate each year reflecting market saturation. EE is expected to decrease future load growth (before any DERs) from 1.4%/year to 0.7%/year on average over the next five years, though the Company does not specify how these projections were developed. EE is allocated to each feeder proportional to each feeder’s share of total energy needs from the most recent historical year.

Rooftop solar Photovoltaic (PV) projections are similarly based on projects in the Company’s queue as well as insights from PV subject matter experts. Projections assume that National Grid fills its 45% share of the state’s existing solar standards by the mid-2020s and will continue to meet its share in the long term. Allocation of system-level PV nameplate capacity is allocated to feeders according to a scoring system, which takes key factors impacting adoption into account such as household income, home ownership, employment stability, and property value. The

Company relies on the Gridtwin tool to rank parcels of land based on viability of solar and allocates non-rooftop solar projections accordingly.

Energy storage impacts are projected assuming that the Company will meet its share of statewide energy storage policy goals to 2025, but there do not appear to be explicit policy goals in Massachusetts for storage beyond that year. In the long term, the Company assumes that its share of energy storage in the state will approximate its load share in the state, around 45%. The Company indicates that, because it currently has a large storage queue of over 1 GW and knows where these projects will be placed, it relies on this information to allocate storage impacts to the feeders serving the relevant areas.

Light-duty electric vehicle (LDV) deployment is developed around compliance with California's ACC-II rules, which have been adopted in Massachusetts. **Long-term projections** are also based on compliance with varying bounds of the ACC-II rules. Medium- and heavy-duty vehicle adoption is based on California's Advanced Clean Trucks rules through 2035. The company takes zip code level socioeconomic information about income and average commuting times and ranks feeders accordingly, in order to allocate personal electric vehicle (EV) adoption. More specifically, the Company incorporates zip code-level data on median household income, the share of individuals with degrees higher than a college level, and commuting patterns to calculate feeder-level propensity scores (assumes a ratio of one feeder per zip code). If a feeder serves multiple zip codes, the Company computes a weighted average propensity score across all zip codes served, using number of residential accounts as weights. The Company reports that neighborhoods with higher income level, higher education rates, and higher commuting times are expected to experience higher personal LDV adoption, an intuitive result that is consistent with the results of allocations in other jurisdictions. Commercial LDV adoption is allocated to feeders based on the number of commercial and industrial (C&I) customers served by each feeder. Medium and heavy-duty vehicle (MHDV) adoption is allocated based on the share of C&I load served by each feeder.

Company electrification targets inform **heat pump adoption** through 2024. Beyond 2024, the Company assumes that its proportional share of the 2030 Clean Energy and Climate Plan's "phased electrification pathways"[1] target will be met. Heat pump adoption is allocated to feeders using an optimization algorithm that is based on the proportions of delivered fuel at each feeder, but assumes that gas customers can also convert to heat pumps.

[1] The Massachusetts Clean Energy and Climate Plan for 2025 and 2030 is a follow-on analysis to the 2050 Decarbonization Roadmap, focused on investigating a range of strategies specifically targeting decarbonizing heat. The study evaluates five scenarios to represent varying portfolios of available clean heating technologies. The "Phased" pathway is defined to incorporate the following parameters: "Rapid adoption of both partial-home and whole-home heat pump systems but with an emphasis on partial-home systems in the 2020s and then whole home thereafter. Some use of clean fuels in 2050."

Finally, the Company projects two categories of demand response programs: ISO-NE programs and the Company retail-level programs. These projections are already baked into the forecasts at the feeder level.

3. Does the Company's baseload econometric load forecasting methodology align with electric utility industry best practice?

Yes, we find that the Company's base load forecasting methodology aligns well with the current load forecasting landscape. Brattle consultants recently inquired with 20 American and Canadian utilities about their total sales and peak demand forecasting methodologies, as well as their approaches for capturing uncertainty across forecasts. The survey found that econometric modeling is the most widely used methodology for load forecasting, followed closely by statistically adjusted end-use (SAE) models. Other modeling tools such as time series trends, Delphi surveys, or simply reliance on customer-reported information (used primarily for C&I customers) were less common. Econometric modeling was also the most common approach for peak demand forecasting according to the survey, far surpassing other methods.

The Company's use of scenario analysis aligns well with industry best practice for capturing uncertainty within econometric forecasts; other reported methods such as Monte Carlo analysis were being utilized less frequently. Utilities cited greater transparency, ease of communicating results, and the ability to develop more policy-driven sensitivities as reasons for choosing scenario analysis over Monte Carlo analysis.

4. Does the Company's load forecast methodology account for the impacts on electricity demand from energy efficiency, beneficial electrification, and other distributed energy resources/flexible resources (e.g., solar PV, energy storage, demand response) align with electric utility industry best practice?

Yes, it does. There are two widely used methods for incorporating the impacts of DERs into econometric models. One approach involves using the actual historical consumption data that already reflect the impact of DERs. The econometric model estimated using this data and the forecasts resulting from this model already reflect the continuation of trends in the adoption of DERs. Any expected deviations in DER adoption trends are incorporated into forecasts in the form of incremental adjustments. While this approach makes the estimation process easier, it has the complexity of estimating the embedded DER impacts in forecasts to determine the incremental DER adjustments.

The second approach involves reconstituting the historical consumption data for the impacts of DERs. Under this approach, any DERs that reduce the load are added back and the DERs that increase the load are subtracted from the historical consumption data. This reconstitution leads to a historical consumption data series that do not reflect any DER impacts. The econometric model estimated using this data and the forecasts resulting from this model similarly do not reflect any DER impacts. The last step is to take the DER projections and apply them to the forecasts resulting from the econometric model.

The Company has followed the second approach, which is a widely used approach by utilities and several major ISOs/RTOs, mostly due to its transparency and simplicity.

5. Has the Company accurately accounted for the Commonwealth's clean energy and climate policy goals in its load forecast and demand assessment?

Yes, the Commonwealth's clean energy and climate policy goals are reflected in the Company's independent projections of DER deployment, the impacts of which are added to the results of the econometric load and peak demand forecasts. As stated in the Company's Electric Sector Modernization Plan, short-run projections of some types of DER deployment (such as EE, heat pumps, solar PV, and Demand Response (DR)) reflect Company-specific project plans and queues. In the longer term, statewide policies such as the Clean Energy and Climate Plan for 2030 (CECP) and the Energy Pathways to Deep Decarbonization 2050 inform solar PV, heat pump, and energy storage targets. Electric vehicle adoption is also anchored in Massachusetts state policy, and is set to follow the LDV and MHDV adoption targets outlined in the ACC-II and ACT rules, respectively. Table 1 summarizes the statewide clean energy and climate policy goals that inform the short- and long-term projections of each DER, where applicable:

TABLE 1: SUMMARY OF DER PROJECTION METHODOLOGIES

Distributed Energy Resource	Short-Term Projection	Long-Term Projection
Energy Efficiency	Company 3-year EE Plan	Incremental annual growth at increasingly slower rate
Solar PV	Company's interconnection queue, SME insights, Company share of State existing solar target	Company share of State policy target under 'All Options' scenario
Electric Vehicles	ACC-II and ACT Rules	ACC-II and ACT Rules
Heat Pumps	Company 3-year EE Plan	State CECP 'Phased Electrification' Scenario Target
Demand Response	Informed by program administrator and existing projects	Similar incremental growth as short term
Energy Storage	Company share of Statewide policy target	Company share of target under CECP/Decarbonization Roadmap

6. Does the Company evaluate multiple scenarios concerning the pace of adoption of new technologies such as electric vehicles, heat pumps, and solar PV?

Yes. The Company evaluates Base, High, and Low adoption scenarios for six categories of DERs reflected in its forecasts. The scenarios appropriately capture uncertainty regarding the level of compliance with statewide clean energy targets, as well as the pace with which the technologies will be adopted in the longer term. Table 2 below summarizes the Base, High, and Low DER scenario methodologies:

TABLE 2: DER SCENARIO DESCRIPTIONS

DER Technology	Base	High	Low
Energy Efficiency	Company plan until 2024, savings grow at slower rate in long-term	Company plan until 2021. Slower decline in persistent savings, higher incremental for residential savings.	Company plan until 2021. Incremental savings 75% of the base case.
Electric Vehicles (On-Road)	CA Advanced Clean Car (ACC-II) lower-bound CA Advanced Clean Trucks (ACT)	ACC-II upper-bound ACT accelerated	Same LDV adoption level with managed charging MHDV lower growth rated based on BNEF 2022 EVO.
Electric Heat Pumps Installations	Company plan until 2024, Company share of CECP 'Phased' goals post-2024.	Company plan until 2024, Company share of CECP 'Full Elec.' goals post-2024.	Company plan until 2024, Company share of CECP 'Hybrid' goals post-2024.
Solar PV Nameplate (Distribution-Level)	Company interconnection queue, and Company share of statewide 'All Options' scenario goal.	Meet 'All Options' goal slightly earlier.	Meet 'All Options' goal slightly later.
Energy Storage Nameplate (Distribution-Level)	Share of statewide policy goals through 2025. All-Options and 100% Renewables targets in 2050	Share of statewide policy goals through 2030. Saturation 10% less per year to 2050.	Saturation begins earlier, at 20-30% fewer new installations each year.
Demand Response	SME-approved projections and guidance through 2024. Post-2024, average annual growth of 2.5%.	SME guidance through 2024. Post-2024, average annual growth of 5%.	SME guidance through 2024. Post-2024, no incremental MW added. Projections held constant.

Source: Extracted from "MECO and Nantucket Electric Company 2030 to 2050 Electric Peak (MW) Forecast", May 2023, Appendix G.

The Company's high and low DER scenarios represent the different decarbonization pathways identified in the Massachusetts 2050 Decarbonization Roadmap, the CECP, and the two transportation electrification policies that Massachusetts recently adopted (ACC-II and ACT). Thus, the adoption scenarios for these DERs continue to be anchored in various levels of clean energy policy aggressiveness.

The Company also conducts a thorough uncertainty analysis on the results of its econometric peak demand forecast, as discussed in the ESMP. The ESMP correctly identifies uncertainty stemming from projecting key economic and demographic variables that drive the baseline forecast, as well as uncertainty due to lack of empirical data on existing heating and transportation electrification. It also identifies uncertainty in the level of technological improvements for technologies whose impacts are not yet widespread. To address this uncertainty, the Company generates as many as 2,000 different scenarios of future electric load growth and peak demand, creating a range of possible outcomes spanning roughly 3,000 MW by 2050.

7. Is the Company's methodology for allocating system-level load growth to distinct planning areas of its network robust?

Yes. My understanding is that the most granular level of load growth allocation is at the feeder level, and that the Company maps and then aggregates feeder-level results to derive forecasts for the Company's 18 Power Supply Areas (PSAs). Based on conversations with the Company and the May 2023 Peak Report, the Company apportions the system-level energy forecast to its 987 feeders based on the recent historical share of total energy that is served by each feeder. Regional energy growth information also informs the allocations of energy efficiency and MHDV adoption at the feeder level. Demographics, heating fuel types, and land availability inform the allocation of solar PV, LDVs, and electric heat pumps to the feeders. Reliance on historical energy growth information to inform the allocation of the system-level energy forecast is appropriate. Information on year-over-year fluctuations of historical feeder-level energy demand would be useful to get a sense of whether these values are highly variable.

8. Does the Company regularly assess the accuracy of its forecasts, and update its methods to avoid systematic over- or under-forecasting?

Yes. The Company relies on well-established practices to track the performance of its econometric models.

To evaluate overall goodness of fit, the Company tracks the model's adjusted R-squared, a statistical test that represents the share of the dependent variable (in this case, energy usage) that is explained by the independent variables. The MECO electric residential use per customer model adjusted R-squared is equal to about 0.98 according to the regression outputs provided in the FY2024 to FY2028 Forecast of GWh Deliveries and Customer Counts (October 2022). MECO's electric commercial use per customer model R-squared is 0.91, and its industrial use per customer model R-squared is 0.83. Customer count model R-squared values range from 0.87–0.99. Nantucket Electric's econometric models show similar, if not slightly lower, R-squared values. These results indicate that the dependent variables across all utility econometric models are generally well-explained by the explanatory or independent variables.

Another important indicator of model performance is the intuitiveness of the independent variable coefficients that come out of the models. The Company appropriately evaluates the directionality of each of its independent variables for intuitive correlation with the dependent variable. Regression outputs for each of the utility models indicate that generally, energy usage per customer is positively correlated with the heating and cooling degree days for all customer classes. Other independent variables included in the commercial and industrial models, such as manufacturing employment and GDP, correlate positively with energy usage per customer.

The Company carries out other important diagnostic assessments of the models, namely tests of statistical significance and autocorrelation within the explanatory variables. Statistical significance of the explanatory variables in all models across utilities is high, with <0.05 p-values reported in the regression outputs for all models (the intercept is an exception).

Finally, the Company conducts extensive analysis of model accuracy over time by comparing projected outputs to actuals as they become available and evaluating model performance error. The Company calculates model error across weather-normalized projected values and actuals at the monthly level, and also tracks cumulative variance across the fiscal year. The most recent two modeling iterations have shown very low annual average variance from actuals 0.63% and 1.2%, respectively. These variance numbers indicate strong forecasting accuracy, on average.

III. Conclusions

National Grid requested that I address eight questions related to the Company's load forecasting framework underlying the ESMP. These questions span issues related to the robustness of the econometric models and methods for allocating DERs to planning areas, and overall strength of the forecasting framework in informing the investment requirements put forth in the ESMP.

The basis for my responses was my review of the Company's forecasting materials and various meetings I participated with the Company's load forecasting experts. I have also completed many load forecasting efforts and assessments for electric utilities and ISOs/RTOs over the course of my career; hence, I am intimately familiar with the issues that were in the scope of this assessment.

In light of the responses to the above issues, I can conclude that the Company's electric load forecast and demand assessment provide a reasonable, robust, and reliable view of how customer demand is expected to grow in light of anticipated economic conditions and Commonwealth clean energy policy goals. However, as it is inherent in the nature of forecasting, there are uncertainties related to whether the forecast drivers will materialize in the way that the Company expects. The Company undertakes a scenario analysis to capture the uncertainty in these drivers. I also understand that the Company has an established process for tracking monthly variances in forecasts versus actuals, and expects to modify forecasts, as well as the proposed investments implied by these forecasts if the observed demand starts to deviate from the forecasted demand.

Exhibit 5: Report on National Grid's ESMP proposal by the Brattle Group

An Assessment of National Grid Electric Sector Modernization Plan

PREPARED BY
Sanem Sergici, Ph.D.

PREPARED FOR
National Grid

AUGUST 31, 2023

Brattle

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Executive Summary

Massachusetts is one of the leading states in the nation with its ambitious clean power targets with the goal to reach net zero by 2050. These goals were articulated in Massachusetts' 2050 Clean Energy and Climate Plan (CECP) and further strengthened with legislation in 2022, *An Act Driving Clean Energy and Offshore Wind* ("2022 Climate Act"). With that goal in mind, the 2022 Climate Act, directed each Massachusetts electric distribution company (EDC) to file an Electric Sector Modernization Plan (ESMP) that identifies upgrades to the distribution and transmission systems, where needed.

National Grid ("the Company") asked me, Dr. Sanem Sergici of the Brattle Group, to provide my independent assessment of the Company's ESMP given the goals of the 2022 Climate Act. I based my assessment on various drafts of the ESMP, numerous meetings with the ESMP team and my review of other comparable distribution planning efforts from other jurisdictions with similarly ambitious climate goals. Based on this review, I find that:

- The Company has demonstrated that its proposed investments are necessary to enable an electrification-based approach to achieving the State's clean energy and climate goals. In order to do so, the Company has developed and implemented a robust spatial load forecasting methodology; identified areas and assets which are at risk of exceeding their rated capacity due to the forecasted load growth; and proposed a five-year investment plan that prioritizes these areas with expected capacity deficiencies for implementation by 2030.
- The Company proposed a suite of technology investments, in addition to the more traditional distribution investments targeting capacity deficiencies, with the goal to empower its customers by giving them more choice and control over their energy decisions. These investments are intended to build upon the Company's existing investments in AMI and expand the platform for customers and other market players to engage in a way to spur innovation, improve system efficiency, and reduce costs.
- The Company has also proposed a suite of technology investments to improve the intelligence and agility of its IT systems, communication networks, and monitoring systems. These investments are increasingly necessary during a time in which generation resources are more variable and/or distributed and the customers' reliance on electricity for most energy needs including transportation and heating will be higher. These investments will help the Company to build a more flexible, resilient, and agile grid.

- The Company's ESMP is responsive to the statutory objectives set for the ESMP in the 2022 Climate Act. More specifically, the Company's ESMP is developed to advance following goals around:
  - Improved grid reliability, communications, and resiliency
  - Enablement of increased, timely adoption of renewable energy and DERs
  - Promotion of energy storage and electrification technologies for decarbonisation
  - Readiness for climate-driven impacts on transmission and distribution systems
  - Accommodation of transportation and building electrification and other new loads
  - Minimizing or mitigating impacts on ratepayers
- The Company's ESMP is comparable in scope to distribution investment plans by other utilities facing similarly ambitious climate goals and objectives. However, the Company is still at an early stage for reliance on NWAs, demand response, TVRs and other load flexibility measures to mitigate load growth, and should build up these capabilities rapidly as it institutes required technology platforms like AMI.
- Overall, the Company's ESMP proposes a reasonable and robust set of network investments, enabling technology solutions, and customer offerings necessary to meet the Commonwealth's climate and clean energy goals.

I. Introduction

Massachusetts is one of the leading states in the nation with its ambitious clean power targets with the goal to reach net zero by 2050. These goals were articulated in Massachusetts' *2050 Clean Energy and Climate Plan* (CECP) and further strengthened with legislation in 2022, *An Act Driving Clean Energy and Offshore Wind.* The latter is aimed at ensuring the grid has the capacity and flexibility to absorb all the variable renewable generation expected to come online and to reliably meet the demands of increased electrification of transportation and buildings. With that goal in mind, *An Act Driving Clean Energy and Offshore Wind* directed each Massachusetts electric distribution company (EDC) to file an Electric Sector Modernization Plan (ESMP) that identifies upgrades to the distribution and transmission systems, where needed. These plans would be structured to meet the Commonwealth's climate and clean energy goals over three planning horizons: 1) a 5-year forecast, 2) 10-year forecast, and 3) a demand assessment through 2050.

Nature of the Engagement

National Grid has developed an ESMP to meet the requirements of this legislation in a way that builds upon their existing investments to enable a clean, reliable, and affordable future for its customers. The Company asked me, Dr. Sanem Sergici of The Brattle Group, to provide my assessment of the ESMP. Specifically, National Grid asked me to address the following issues:

1. Has the Company demonstrated that its proposed investments are needed to enable the Commonwealth to achieve its clean energy and climate goals?
2. Has the Company proposed technology investments to empower its customers by having more choice and control over their energy decisions?
3. Has the Company proposed other technology investments to improve its planning, management, and communication functions needed to serve all customers reliably?
4. Does the Company's plan advance the statutory objectives set for the ESMP in "An Act Driving Clean Energy and Offshore Wind" (the 2022 Climate Act), as codified in G.L. c. 164, §§ 92B and 92C?
5. How does the Company's plan compare to plans by other utilities in other jurisdictions that are scoped to meet comparable climate and clean energy objectives?
6. Does the Company identify a reasonable set of policy and regulatory enablers?
7. Does the Company's plan have a reasonable and robust set of proposed network investments, enabling technology solutions, and customer offerings necessary to meet the Commonwealth's climate and clean energy goals?

The remainder of this report is organized around these seven issues. To address the issues, I reviewed Company's ESMP and attended several meetings with the subject matter experts, including a full-day working session with the ESMP team. Throughout the review process, I had plenty of opportunities to ask questions and provided my feedback on earlier drafts of the ESMP. In addition to reviewing Company's approach and proposed plan on its own merits, I was able to draw comparisons to similar filings in other jurisdictions with equally ambitious climate goals, such as New York, California, and Minnesota. While I was able to gain a comprehensive understanding of the Company's overall approach to ESMP and basis for various decisions involving forecasts and proposed investments, I did not undertake a "quantitative" verification of any of their analysis, forecasts, and capital budgeting. Therefore, my review will only be restricted to the Company's approach and methods in developing the ESMP.

Summary of Expert Qualifications

Dr. Sanem Sergici is a Brattle Principal and an energy economist with twenty years of consulting and energy research experience. Sanem's consulting practice is focused on understanding customer adoption of and response to innovative rate designs, distributed energy resources, and emerging technologies. She regularly assists her clients in matters related to rate design, electrification pathways, grid modernization investments, load forecasting, and resource planning. She led numerous studies in these areas that were instrumental in regulatory approvals of grid modernization investments and smart rate offerings for electricity customers. More recently, Dr. Sergici undertook several studies that explore the impact of electrification on grid investments and investigate the role of customer side pathways in meeting climate goals. She has filed testimony quantifying the potential benefits of AMI investments for a Pacific Northwest utility and authored a report titled, "Reviewing the Business Case and Cost Recovery for Grid Modernization Investments," that reviewed ten recently approved grid modernization projects, cost recovery mechanisms, and documents how grid modernization technologies have benefitted customers and utilities. Dr. Sergici's full resume and qualifications are provided in the Appendix.

Dr. Sergici regularly publishes in academic and industry journals and presents at industry events. She received her PhD in Applied Economics from Northeastern University in the fields of applied econometrics and industrial organization. She received her MA in Economics from Northeastern University, and BS in Economics from Middle East Technical University (METU), Ankara, Turkey.

II. Commentary on Key Issues

In this section, I provide commentary on each of the seven key issues I have been asked to address by the Company:

1. Has the Company demonstrated that its proposed investments are needed to enable the Commonwealth to achieve its clean energy and climate goals?

Yes, it has. The Company's ESMP identifies the additional investments necessary to enable an electrification-based approach to achieving the State's net zero goals. In order to do so, the Company has developed and implemented a robust spatial load forecasting methodology and presented a view for future demand incorporating expected levels of electrification, energy efficiency, and other distributed resources. More specifically, the Company conducted an electric demand assessment analysis for three planning horizons: 5-year (2030), 10-year (2035), and 2050.

Having developed feeder/substation level forecasts for the 5-year and 10-year planning horizons, and the current demand levels observed at these feeders/substations, the Company applied its "distribution planning criteria" to determine which assets are at risk of exceeding their rated capacity due to the forecasted load growth, including electrification, and by when. For each of the identified needs, the Company has developed the scopes of work that would be effective in addressing the capacity deficiencies identified through the demand assessment. Those areas at highest risk of overload have been prioritized in five-year investment plans recommended through this ESMP for implementation by 2030. Similarly, the ten-year investment plan was developed to address assets with projected overloads by 2035.

In addition to the grid infrastructure investments proposed as a result of this capacity deficiency analysis, the Company proposed new technology platform investments and customer-facing programs that will build upon the Company's existing and proposed investments and programs preceding ESMP. I understand that the Company has proposed core grid investments to maintain and, in some cases, strengthen the grid to maintain reliable operations through its *Rate Case*. It has received approval for a portfolio of grid modernization investments, including the build out of ADMS, ADA and DERMS solutions, to improve the visibility into distribution system operations and the seamless integration of DERs into grid operation, through its *Grid Modernization Plan.* The Company is in the process of deploying AMI with a goal to complete its rollout by 2029. In addition, it has received approval for various energy efficiency, demand response, and heating and transportation electrification incentive programs that will help improve "load flexibility" in the system, while accelerating the pace of electrification.

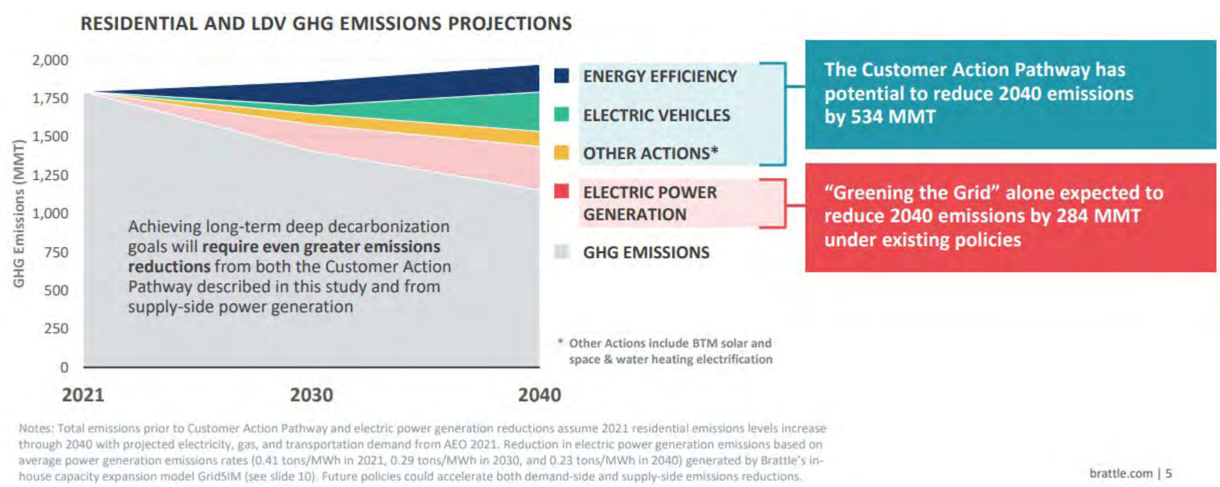
As I will elaborate below, the network, technology, and the customer facing programs proposed in the ESMP are complementary to the Company's previous investments.

2. Has the Company proposed technology investments to empower its customers by having more choice and control over their energy decisions?

Yes, it has. My understanding is that the Company has structured its ESMP plan around four overarching principles. First, the plan intends to build a grid, which is reliable and resilient in the face of changing weather patterns and increased reliance on electricity to meet overall energy needs. Second, the plan strives to empower customers through enabling more choice and control through technology investments. The third principle is to leverage innovation, flexibility, and efficiency in all planning functions to meet customer needs. The fourth principle is to plan and execute all investments to create a more just, equitable, and affordable future for all National Grid customers and communities.

National Grid understands that the customers are becoming increasingly engaged in energy consumption decisions, desiring and demanding more information that can enable them to identify ways to lower their energy usage, reduce their carbon footprint, and effectively leverage new energy technologies. The Company's ongoing AMI deployment will lead to granular data and two-way communication capabilities and unleash a multitude of possibilities for customers to become "empowered" through their participation in time-varying rates, behavior-based, and load flexibility programs. These programs will also help National Grid to meet the State's ambitious climate goal involving the integration of variable renewable energy resources into the grid and electrification of building and transportation sectors. In a recent study[1], I and my team at Brattle demonstrated that customer-driven actions are key in achieving ambitious decarbonization goals and these actions have the potential to reduce GHG emissions by nearly twice as much as supply-side reductions alone will contribute under existing policies.

FIGURE 1



Source: Sergici, et al. (2021)

[1] Same Sergici, et al., "The Customer Action Pathway to National Decarbonization," prepared for Oracle, September 2021. https://www.brattle.com/wp-content/uploads/2021/10/The-Customer-Action-Pathway-to-National-Decarbonization.pdf

The Company's ESMP proposes several technology investments that will build upon the in-flight technology investments such as AMI and provide customers with better and more timely information to support their energy consumption and DER investment decisions. These technology investments are also designed to support new and innovative rates that will be offered to customers to help them better manage their energy costs and help mitigate their impact on peak demand growth. The Company proposes three types of technology investments that will directly impact customer empowerment:

- **Metering and billing systems.** These include the technologies to measure customer energy usage and undertake billing of more innovative rate designs
- **Customer portals.** These include the customer-facing and internal systems to manage customer programs such as those related to energy efficiency, electric vehicles, and new customer interconnections.
- **Data platforms.** These include the organization of and easy access to data that will improve customers' ability to manage their usage and bills and the Company's ability to operate and plan the grid in a more timely and efficient manner.

These investments will build upon the Company's existing investments in AMI and expand the platform for customers and other market players to engage in a way to spur innovation, improve system efficiency, and reduce costs. If this platform is not fully developed, then the customers who are served by that system will have limited access to innovation and saving opportunities.

3. Has the Company proposed other technology investments to improve its planning, management, and communication functions needed to serve all customers reliably?

Yes, it has. While the ESMP proposes proactively to expand the capacity of the distribution system through new and upgraded power lines, transformers, and substations to accommodate more clean and distributed energy and electric growth, it also strives to improve the intelligence and agility of IT systems, communication networks, and monitoring systems. With these objectives in mind, the Company is proposing three additional categories of technology investments:

- **Network management and communications.** These include the technologies to communicate with, monitor, and control assets on the Company's network; accommodate two-way information flows; and manage and respond to grid outages and abnormal system conditions.

- **Asset planning, management, and work execution.** These include the systems that support grid planning and design, construction and capital deployment, and regular system maintenance and field operations.
- **Security.** These include measures in place to ensure the security of the technology systems from potential cyber threats and attacks.

We are now rapidly heading into a new paradigm in which generation resources are more likely to be variable and/or distributed and the customers' reliance on electricity for most energy needs including transportation and heating is ever increasing. Given these changes, it is essential for National Grid to build a flexible, resilient, and agile grid. The grid should be able to sense disturbances; communicate imbalances and abnormalities to control centers swiftly; self-heal in most occasions; and have the right protections against cyberattacks. I believe that National Grid's proposal for these investments is timely and it will allow the Company to get ahead of potential challenges associated with a more distributed, variable, and essential grid.

4. Does the Company's plan advance the statutory objectives set for the ESMP in *An Act Driving Clean Energy and Offshore Wind* ("2022 Climate Act"), as codified in G.L. c. 164, §§ 92B and 92C?

The G.L. c. 164, § 92B(a) of the 2022 Climate Act directs each electric company to develop an electric-sector modernization plan to proactively upgrade the distribution and, where applicable, transmission systems 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, transmission systems; 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 21N.

The Company's ESMP is responsive to these statutory objectives set for the ESMP in the 2022 Climate Act. More specifically:

- The Company's plan undertakes a careful demand assessment for the 5-year, 10-year, and 2035–2050 periods to identify the expected capacity deficiencies at the substation and feeder levels, given the target levels of electrification implied by State policies. The Company notes that "the major substation construction projects typically take 3 to 10 years to execute." Given this lead time in construction, it is prudent for the Company to proactively expand capacity in problem areas, so that the **reliability** in these areas are not compromised due to a rapid growth of electric demand. Similarly, asset hardening and flood mitigation methods were incorporated in the scopes of work identified for the 5-year plan to advance **resiliency** goals. It is important to note that the Company prioritizes investments in areas with highest risk of overload in the 5-year plan to ensure that ratepayer impacts do not become too burdensome.
- The Company's plan identifies new load flexibility opportunities through VPPs and time-varying rates, which will **enable integration of renewable energy** by mitigating their intermittency. While some of these elements have not been directly accounted for in the load forecasts underlying the proposed investments, the Company acknowledges that it will work on developing the capabilities, and at scale, as soon as the technical capabilities are there (i.e. AMI for TVRs) and several demonstration projects with VPPs are completed. Similarly, The Company will enable the **increased adoption of DERs** through more up to date and transparent hosting capacity information and expedited interconnection process, facilitated by the DERMS investment. When the AMI deployment has advanced and the new billing systems are fully functional, the innovative rate option offerings, including TVRs, may also incentivize customers to adopt certain types of DERs, such as solar plus storage systems.
- The Company explicitly accounts for the **hosting capacity for storage interconnections** in its regional planning analyses. Batteries require both hosting and load serving capacity at the location of their connection because they both charge and discharge. This implies that the increased penetration for batteries will create both capacity deficiency and hosting capacity constraints. The Company's planning effort takes this nuance account and therefore ensures that the energy storage can interconnect, charge, and discharge without constraints, helping to promote adoption of storage. Similarly, the Company undertakes an

analysis to determine the capacity deficiency by planning area, taking into account the **expected load growth due to electrification** and the impact of DERs, at the substation and feeder level. National Grid's goal is to stay head of customers in the capacity planning efforts and build the capacity ahead of customers' demand for electrified end-uses increases rapidly. This will prevent adverse customer experience associated with not being able to charge their EV at home, or install a new heat pump because there is not sufficient capacity at the feeder or substation level.

- The Company's ESMP follows an approach in which investment needs are identified and then prioritized based on the urgency of needs in the 5-year and 10-year planning horizons. The Company also indicates that it plans to track load growth during the planning cycle and make modifications as necessary if some of the expected capacity deficiencies do not materialize or they appear at a slower pace. By adopting this flexible approach to planning, the Company expects **to minimize the impact of ratepayers**. Moreover, as the Company builds some of the capabilities associated with time-varying rates, load flexibility and NWAs, some of these needs can be mitigated through non-wires solutions.

5. How does the Company's plan compare to plans by other utilities in other jurisdictions that are scoped to meet comparable climate and clean energy objectives?

The Company's plan is largely comparable in scope to plans by other utilities facing similarly ambitious climate goals and objectives. More specifically, the ESMP is comparable to these three plans in terms of: i) the robustness and granularity of the load forecasting framework used; ii) the robustness and granularity of DER forecasting/allocation methods; and iii) the status/plans for AMI, ADMS, DERMS, as well as other technology investments.

TABLE 1

State	NY	CA	MN
Utility	Consolidated Edison	PG&E	Xcel Energy
Filing Year	2023	2021	2021
Climate Goal	Net zero by 2050	Net zero by 2045	Net zero by 2050
Source	Distributed System Implementation Plan	2021 Distribution Grid Needs Assessment	Integrated Distribution Plan 2022-2031
Planning Horizons	DSIP horizon is 5 years but several component studies have longer horizons.	5-year forecast for identifying substation and feeder needs; 10-year horizon for "Pre-Application Projects"; 3-year horizon for line section capacity and Volt/Var needs.	10 years

State	NY	CA	MN
Planning criteria	Grid upgrades are based on probabilistic approach using "Network Reliability Index (NRI)". ConEd defers resolving overloads of up to 10% if NRI is less than 0.2. Scenario analysis is also used to inform these decisions. 20-yr load forecast flows into system planning process.	Grid needs identified based on 5-year forecast and need for capacity, voltage support, reliability, and/or resiliency.	Generally load feeders to 75% of capacity under N-0 conditions; voltage imbalance goal of less than 3%
Granularity of Load Forecasting	System-wide, network, feeder, area stations	Transmission access area, customer class, substation, feeder level	System, feeder, substation
Granularity of DER Forecasting/Allocation Methods	Network level	System wide, distribution bank and feeder	System, feeder, substation
AMI Status	Over 98% deployed	Over 98% deployed	Started deployment in 2022; scheduled through 2024
ADMS Status	Does not currently have ADMS but has a suite of systems that perform some of the functionalities of an ADMS. Phased plan to add more ADMS functionalities.	Planned	Some functionalities in service since 2021; further investments underway
DERMS Status	Phased implementation plan	In progress	Anticipate need for DERMS and exploring best solutions.
Other proposed technology investments	Data communications infrastructure, grid sensors and control devices, distribution automation, GIS system, piloting thermal energy networks		Field Area Network, LoadSEER for advanced distribution system planning, Fault Location Isolation and Service Restoration (FLISR)
Availability of TVRs	Available	Available	TOU rate pilot underway
Role for DR/LoadFlex/VPPs	EE and Clean Heat programs incentivize efficient measures. Focus on expanded savings and budgets over time.		Considered as mitigation options for areas with distribution needs
Role for NWAs	Institutionalized NWAs as a formal element of annual capital planning process.	Has a framework for soliciting NWAs	Considered as alternative option based on cost-benefit analysis
Energy Justice/affordability considerations	Specific LMI components of EE programs		Resilient Minneapolis Project (RMP) initiative seeks to improve communities' resilience while also advancing distribution plans by developing microgrids in certain areas.
Climate Vulnerability Considerations	Climate Vulnerability Study conducted and findings used as inputs to load forecasts and in prioritization of operations and planning.		

Based on this comparison, there are also a few areas where the Company should continue to build up their capabilities. For instance, the role of NWAs will exceedingly increase in capacity planning efforts to slow down the pace of investments and avoid/defer some of the capacity needs. The Company should consider developing an NWA framework, which would make NWAs a formal element of the capacity planning process, as is the case in New York. Another important area for the Company to consider in future planning efforts is to integrate climate vulnerability conditions, and make them part of a formal scenario analysis. Last but not least, the Company's reliance on demand response, TVRs, and in general load flexibility measures has been limited, mostly due to not having established and mature programs in these areas. The Company should build up these capabilities incrementally as their AMI deployment is underway, and aim to reach scale over the next 5-10 years.

6. Does the Company identify a reasonable set of policy and regulatory enablers?

Yes, it does. The Company has developed the ESMP to enable the decarbonisation pathway as envisioned in the 2022 Climate Act. The Act aims to ensure the grid has the capacity and flexibility to absorb all the variable renewable generation expected to come online and to reliably meet the demands of increased electrification of transportation and buildings. As one of the leading distribution utilities in the Commonwealth, the Company has a profound role in executing the vision of the Act through its investments in the network, technology solutions and customer programs. However, the Company needs a reasonable set of policy and regulatory levels to ensure that it has the capacity, incentives and agility in undertaking the investments to prepare the Commonwealth for a cleaner and more distributed generation mix and largely electrified energy demand.

The Company identifies the following policy and regulatory levels to realize the ESMP benefits:

- Timely cost recovery for electric network investments
- Reforms to existing siting and permitting processes
- Regulatory support for AMI-enabled time-varying rates
- Regulatory framework for evaluation, development, and compensation of non-wires solutions and aggregated load flexibility offerings
- Integrated planning of electric and gas systems
- Support an equitable and affordable energy transition

Many of the existing regulatory frameworks were developed at a time when distribution utilities were operating under very different circumstances (i.e. centralized generation resources, more deterministic demand forecasts, higher reliance on fossil fuels, independent electric and gas business models, legacy billing and metering systems etc.) compared to today. While existing regulatory and ratemaking practices might have been appropriate responses at the time, they are likely to fall short of being responsive to the demands of the current times. Energy transition will bring along large levels of investment needs and enabling the utilities with timely cost-recovery mechanisms will be key to undertaking this transformation effectively. At the same time, it will be essential to mitigate the pace of these investments through demand side solutions, including NWAs, load flexibility and time-varying rates to achieve this transition in an affordable way.

Moreover, the electric and gas business models are now closely linked to each other as the pace of electrification has a direct impact on the gas demand and gas infrastructure needs. Therefore, it may be beneficial to coordinate the planning functions for both businesses to allow for a joint optimization of investments, which may warrant savings to the customers.

7. Does the Company's plan have a reasonable and robust set of proposed network investments, enabling technology solutions, and customer offerings necessary to meet the Commonwealth's climate and clean energy goals?

Yes, it does. As I described above in my response to questions 2 and 3, the Company has proposed network investments and customer solutions that will complement and build upon the investments the Company has made to date. These portfolio of investments will allow the Company to run its operations more efficiently with better and more timely information through ADMS and increase the value of the AMI investments by utilizing the granular consumption data for implementing time varying rates and a plethora of other load flexibility programs. As the Company builds and starts to utilize these capabilities, it will be able to rely more on the load flexibility measures such as managed charging programs, smart thermostat programs for heating, behind-the-meter storage control programs, and more broadly VPPs to mitigate the pace of electrification related load growth. Similarly, the DERMS investment will increase the information availability at the grid edge; will provide visibility and control of a diverse portfolio of distributed resources to address local or system level constraints. These visibility and control capabilities will be exceedingly important for the Company to manage the grid reliably and cost effectively, as the State makes rapid progress towards meeting its clean energy and electrification. I also encourage the Company to develop an NWA framework and work towards making NWAs an essential element of capacity planning.

III. Conclusions

National Grid requested that I address seven questions related to the Company's proposed ESMP. These questions span issues related to the scope of the ESMP; reasonableness of proposed investments and whether the ESMP is responsive to the requirements set forth in the 2022 Climate Act.

The basis for my responses was my review of the Company's draft and final ESMP materials; various meetings I participated with the ESMP team subject matter experts. I have also been actively working on similar energy transition issues over the course of my career of 20 years. I have authored reports on grid modernization and filed testimony on related matters.

I conclude that the Company's ESMP proposes a reasonable and robust set of network investments, enabling technology solutions, and customer offerings necessary to meet the Commonwealth's climate and clean energy goals. The Company follows a robust approach to developing load forecasts to determine the expected capacity deficiency at the feeder and substation level, taking into account the expected levels of transportation and building electrification and other DERs. Next, the Company takes these locationally granular forecasts and determines which feeders and substations are expected to have capacity deficiency in the next 5-year and 10-year planning horizons. Based on this analysis, the Company proposes a set of network investments by prioritizing them based on the urgency of the needs. In addition, the Company proposes a robust set of technology investments, which will improve the intelligence, and agility of IT systems, communication networks, and monitoring systems and build upon the grid modernization investments the Company has been undertaking. These systems together will also enable a richer set of customer offerings including time varying rates and load flexibility programs, which will lead to better utilization of system resources and present customers with bill savings opportunities.

Exhibit 6: Resume of Sanem Sergici (Brattle Group)

Sanem Sergici

PRINCIPAL

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Dr. Sanem Sergici is a Principal in The Brattle Group's Boston, MA office specializing in innovative retail rate design and economic analysis of distributed energy resources (DERs). She regularly assists her clients in matters related to electrification, grid modernization investments, emerging utility business models and alternative ratemaking mechanisms.

Dr. Sergici has been at the forefront of the design and impact analysis of innovative retail pricing, enabling technology, and behavior-based energy efficiency pilots and programs across North America. She led numerous studies in these areas that were instrumental in regulatory approvals of grid modernization investments and smart rate offerings for electricity customers. She also has significant expertise in resource planning, development of load forecasting models and energy litigation.

Dr. Sergici regularly publishes in academic and industry journals and presents at industry events. She received her PhD in Applied Economics from Northeastern University in the fields of applied econometrics and industrial organization. She received her MA in Economics from Northeastern University, and BS in Economics from Middle East Technical University (METU), Ankara, Turkey.

AREAS OF EXPERTISE

- Electrification
- Innovative Retail Electricity Pricing
- Grid Modernization
- Distributed Energy Resources
- Decarbonisation Pathways and Resource Planning
- Utility Regulatory and Business Models
- Demand Forecasting

EXPERT TESTIMONY AND REGULATORY FILINGS

Before the New Jersey Board of Public Utilities, “New Jersey Energy Master Plan Ratepayer Impact Study,” report filed August 2022 (with G. Kavlak, K. Spees, R. Janakiraman)

Before the British Public Utilities Commission, “A Review of BC Hydro’s Optional Residential TOU Rate,” report filed on behalf of BC Hydro in the company’s Optional Residential Time-of-Use Rate Application, February 21, 2023 (with R. Hledik).

Testimony before the State of New Hampshire Public Utilities Commission, Docket No. DE 21-078, In the matter of Electric Make Ready and Demand Charge Alternative Proposals, on behalf of the New Hampshire Department of Energy, February 28, 2022.

Filed testimony before the Washington Utilities and Transportation Commission in the Matter of Puget Sound Energy General Rate Case. Docket UE-220066 and Docket-UG220067, January 31, 2022.

Before the Public Service Commission of the District of Columbia, “Pepco’s Climate Solutions 5-Year Action Plan: Benefits and Costs,” report filed on behalf of Pepco in Formal Case No. 1167, January 2022 (with S. Sergici, M. Hagerty, M. Witkin, J. Olszewski, and S. Ganjam).

Testimony before the State of New Hampshire Public Utilities Commission, Docket No. DE 20-170, In the matter of Electric Distribution Utilities Electric Vehicle Time of Use Rates, on behalf of the New Hampshire Department of Energy, October 13, 2021.

Report filed before the Public Service Commission of the District of Columbia, “An Assessment of Electrification Impacts on the Pepco DC System,” on behalf of Pepco in Formal Case No. 1167, August 27, 2021 (with R. Hledik, M. Hagerty, and J. Olszewski)

Testimony before the Nova Scotia Utility and Review Board in the Matter of The Public Utilities Act, R. S. N. S. 1989, c380, as amended and Application by Nova Scotia Power Incorporated for Approval of Time-Varying Pricing Tariff Application - M09777, May 17, 2021.

Filed rebuttal evidence before the Nova Scotia Utility and Review Board in the Matter of The Public Utilities Act, R. S. N. S. 1989, c380, as amended and Time-Varying Pricing Tariff Application - M09777, April 22, 2021.

Filed direct evidence before the Nova Scotia Utility and Review Board in the Matter of The Public Utilities Act, R. S. N. S. 1989, c380, as amended and Time-Varying Pricing Tariff Application - M09777, November 30, 2020.

Testimony before the State of New Hampshire Public Utilities Commission, Docket No. DE 19-057, Distribution Service Rate Case, on behalf of the Staff of the New Hampshire Public Utility Commission on rate design studies, December 20, 2019.

Testimony before the State of New Hampshire Public Utilities Commission, Docket No. DE 19-064, Distribution Service Rate Case, on behalf of the Staff of the New Hampshire Public Utility Commission on rate design studies, December 6, 2019.

SELECTED CONSULTING EXPERIENCE

ELECTRIFICATION

- For ERCOT, developed a repeatable process for forecasting electric vehicle load impacts at the substation level out to 2029, for use in their System Planning Assessment and provide an "interactive tool" that could be used to easily replicate and update the analysis in the future. Brattle team developed LDV, MDV, and HDV forecasts for 10 years and allocated these forecasts to the individual substations based on a propensity score model. This model takes into account income, population density and economic activity in a given zip code, and uses this information to allocate forecasted EVs to the substations. After developing EV forecasts for each substation, our team has also developed 8760 charging profiles for all EVs charging at the substation, allowing ERCOT to understand the implications for this new load for transmission planning purposes.
- Development of an Econometric Based EV Forecast for Baltimore Gas and Electric Company. The Brattle Team has compiled a comprehensive repository of national EV adoption related data and estimated an econometric model to explain the drivers of US EV sales, using data from 50 states, from 2011-2019. BGE had expressed a strong preference for a model that relates drivers of EV adoption to sales and did not want to use top down forecasts or a diffusion models due to their inflexibility to update assumptions. With the econometric model, it was possible to develop various forecasts depending on federal, state and utility incentives; different battery cost trajectories; alternative EV TOU rates; utility owned charging infrastructure among many other drivers. This econometric model was also supplemented by another system-dynamics based module that captured the supply side drivers of EV sales such as increasing model availability, charging infrastructure and improved R&D activities. Brattle team developed alternative EV sales scenarios for BGE's service territory and analyzed the impacts of EV load

(under managed and unmanaged scenarios) on utility ratemaking, infrastructure investments and other financial metrics.

- For PGE, led the Brattle team developing EV potential as part of PGE's 2021 DER potential study. Developed light, medium and heavy duty vehicle forecasts through 2040, and quantified the peak, energy and EV charging infrastructure implications of these EV forecasts.
- For Pepco DC, conducted analysis to forecast how the utility's load would increase if aggressive decarbonization goals are met through electrification, and to determine the extent to which energy efficiency and load flexibility measures could mitigate that load growth, highlighting the key role that load flexibility will play in facilitating the decarbonization transition.
- For SRP, developed an updated EV adoption forecast for their territory to inform the potential scale of the managed charging program, analyzed the system-level benefits of managed EV charging to inform the level of customer incentives, including energy and capacity cost savings, and reviewed the design of their pilot study
- For Pepco, assessed the benefits and costs of the company's Climate Solutions Plan. The Plan consists of 62 demand-side initiatives, including large energy efficiency, building electrification, and transportation electrification portfolios. The analysis quantified the energy system and environmental benefits of the programs and evaluated the target scale of the impact of the programs. Led a series of stakeholder workshops on the study findings and methodology. The final report was filed with the DC PSC.

GRID MODERNIZATION

- Analyzed the impacts of electric utility infrastructure investment on system reliability and resiliency for a Northeastern Utility, following major weather events. Primary area of analysis involved estimation of economic value of investments to customers using value of lost load (VOLL) metrics for electric system investments.
- Authored a comprehensive report for National Electrical Manufacturer's Association (NEMA) that reviews most recently approved 10 major grid modernization projects. Report discusses business cases and cost recovery mechanisms for each of these projects and documents how grid modernization technologies have benefitted customers and utilities.
- Worked with the Puget Sound Energy Grid Modernization team to identify and quantify the customer-facing use cases enabled by the Company's AMI investment. Authored a report detailing the analysis and filed testimony.
- For an investor owned utility, developed a comprehensive survey of cost recovery methods used to recover the costs associated with climate and grid modernization investments, based on the implementations in jurisdictions with major climate goals.

- Served as a member a Technical Advisory Group (TAG), which was formed by Department of Energy (DOE) and Lawrence Berkeley National Laboratory (LBNL). Reviewed and provided feedback on the experimental designs of the utilities that were awarded Smart Grid Investment Grant projects and participated in periodic project review meetings with utilities to review and provide feedback on the interim results as they implement their projects. As part of this assignment, authored a guidance document that discussed different impact evaluation methods, which can be selected by the utilities. This document was shared with the utilities and other TAG members.
- Assisted Pepco Holdings, Inc. to analyze the Phase I of its Conservation Voltage Reduction (CVR) program in its Maryland Service Territory. First of its kind, this econometric study compares consumption of the treatment and control groups before and after the implementation of CVR. More specifically, a regression analysis was conducted to compare the usage levels of treatment and control group customers to determine whether the CVR treatment resulted in statistically significant conservation and peak demand impacts. The analysis accounts for exogenous factors such as weather, calendar and seasonality impacts as well as utility energy and demand savings programs.

DECARBONIZATION PATHWAYS AND RESOURCE PLANNING

- For New Jersey Board of Public Utilities, conducted a comprehensive electric and gas consumer total energy cost impact study to assess the energy burden for customers across several customer classes across all major gas and electric utilities in the state. Estimated the impacts of clean energy policies on different customer segments (e.g. customers adopting electric vehicles vs. customers with a gasoline car). Study identified equity implications, including impacts on low-income consumers and consumers with delayed electrification relative to others. The study can be accessed here.
- For Oracle Utilities, estimated the reduction in greenhouse gas (GHG) emissions that could occur by 2030 and 2050 if customer adoption of GHG-reducing technologies, including energy efficiency, rooftop solar, electric vehicles, and electric heat pumps, rises to an aggressive and achievable level.
- For a large Canadian utility, serving as an advisor on the utility's load flexibility assumptions in its integrated resource plan.
- Evaluated how policy reforms could increase access and decrease costs of C&I renewable procurement for the REBA Institute, a group representing commercial and industrial (C&I) customers in the United States, through utility subscription programs, power purchase agreements, and third-party retailer providers. The report finds that there is much potential to

increase C&I procurement and costs, but the policy pathway to enable these results is dependent on state characteristics. The report finds that introducing supply choice has the greatest potential to increase access but presents uncertainty regarding costs, and that utility subscription programs can present significant near-term opportunities.

- Assisted the New York City's Mayor's Office of Sustainability to evaluate how a carbon trading scheme would impact the costs and benefits of implementing Local Law 97, an ambitious building-sector decarbonization law that mandates 80% emission reductions by 2050. In collaboration with larger consulting team, Brattle team evaluated building segment data regarding the size and energy use of buildings covered by LL97, reviewing and modeling efficiency and electrification emission abatement retrofits, modeling building owner decision making to comply with the law, and designed a carbon trading policy to ensure the program meets the needs of the city government, environmental justice community, and ultimately lowers societal costs.
- Led the Brattle team that assisted the New York City Mayor's Office of Sustainability with the development of New York City's Roadmap to 80 x 50. The Brattle team analyzed the change in energy-sector greenhouse gas (GHG) emissions resulting from more than six future scenarios. These scenarios explored the impacts of aggressive energy efficiency efforts, off-shore wind, and the continuance of low natural gas prices on the emissions footprint of New York City. The analysis shows that in order to reach 80 x 50, New York City will need to achieve a significant portion of its GHG reductions as a result of a dramatic shift towards a renewables-based grid. This shift towards renewables must overcome the anticipated retirement of nuclear facilities prior to 2050 and will be supported by the implementation of New York State's Clean Energy Standard and the declining cost of renewable energy.
- Conducted a study involving "solar to solar" comparison of equal amounts of residential- and utility-scale PV solar deployed in Xcel Energy Colorado's Service Area. Calculated costs and benefits of each of these two different but equally sized solar options, i.e., avoided energy, capacity and distribution network costs and others. The study found carbon reductions were greater on utility scale systems because the solar energy per MW is much higher on utility-scale due to better placement and tracking capability.
- Assisted the Southern Company IRP team to explore the impacts of modeling energy efficiency on the demand side (involves screening each EE measure for cost-effectiveness outside of the resource planning model) versus on the supply-side (each EE measure is represented as part of an EE supply curve, which directly competes with generation resources in the model's capacity planning decision algorithm)
- Advised Nova Scotia Power Inc. on the reasonableness of the DSM scenarios and strategies that are being modeled in their Integrated Resource Plan (IRP). This effort also involved advising the

Company on a variety of DSM issues and building up a model that quantifies the rate impacts for program participants and non-participants based on the selected DSM scenario.

- Coauthored the State's Annual Integrated Resource Plan (IRP) for the Connecticut Department of Energy and Environmental Protection (DEEP). This effort involved development of scenarios and strategies for an electric system to meet long-range electric demand while considering the growth of renewable energy, energy efficiency, other demand-side resources. Led the development of demand side management and emerging technology resource strategies and analyses involving these resources.
- Developed a model to assess the prudence of an electric utility's power procurement strategy in comparison to several other alternative options. As a result of this model, she assessed whether it is prudent to recover the congestion and loss costs associated with utility's chosen strategy from ratepayers in a state regulatory proceeding.
- Assisted in preparation of a marginal cost study for an integrated electric utility. The study estimated the incremental costs to the utility of serving additional demand and customer by time period, sub-region, and customer class. The costs were identified as energy, capacity and customer related for generation, transmission, and distribution systems of the utility.
- Assisted in developing an integrated resource plan for major electric utilities. Contributed to the design of future scenarios against which the resource solutions were evaluated. Designed scenarios were driven by external factors including fuel prices, load growth, generation technology capital costs, and changes in environmental regulations. Forecasted the inputs series for the resource planning model consistent with each of the designed scenarios.

DISTRIBUTED ENERGY RESOURCES

- For a U.S. utility, reviewed the utility's benefit cost assessment model used to evaluate distributed energy resources for alignment with commission orders and staff guidance. The assessment identified areas for refinement, including increasing the temporal and geographic granularity of the model. As part of the review, the Brattle team provided insights into potential misalignments between the valuation of transmission and distribution investment deferral within the model, customer value, and system value. The Brattle team rebuilt the model from the ground-up to allow for intuitive use and ensure that assumptions are clearly articulated and well-documented.
- For a DER software developer, estimated the potential market value of residential load flexibility offerings across five utilities. The analysis highlighted that the load flexibility value proposition varies significantly depending on system and market conditions. The final report is a key input to the company's load flexibility business case.

- For a large east-coast utility, reviewed benefit cost framework and model data to evaluate non-pipeline alternatives. The review included treatment of geographic differences in marginal costs due to pipeline access, and the Brattle team rebuilt the model from the ground-up to allow for intuitive use.
- For a large east-coast utility, developed a benefit-cost analysis model to screen non-wires alternative projects.
- System Dynamics Modeling of DER Adoption and Utility Business Impacts. Led the development of Brattle's Corporate Risk Integrated Strategy Platform (CRISP) model and assisted utility clients with the implementation of this model. CRISP is based on System Dynamics approach, which creates simulations based on dynamic feedbacks between utility policies and customer behavior, providing a new perspective on how much and how fast the "utility of the future" must evolve. The focus of these modeling efforts was to help utilities anticipate and accommodate distributed energy resources (DERs) as they become more economical and more widely adapted by retail electricity customers, and to evaluate the sustainability of their traditional cost-of-service business model in the face of such trends.
- For EPRI, conducted a study to explore methods for incorporating DERs into integrated resource planning. A unique feature of this study was the use of Brattle's capacity expansion model, GridSIM, to quantitatively illustrate the implications of various DER modeling techniques. In the first phases of the engagement, we assessed the implications of different approaches to modeling energy efficiency (EE) and demand response (DR), such as the advantages and disadvantages of modeling these resources on the "supply side" versus the "demand side" of the model. The current phase of the project focuses on electric vehicles (EVs) and rooftop solar, and includes a review of techniques for forecasting adoption of these technologies, as well as modeling the resource impacts of growth in EV adoption.
- Estimated NEM cross-subsidies using data from sixteen utilities. Used cost-of-service methodology to compare NEM customers costs on the system vs. revenue collection from these customers using company COS studies, and supplementing it by publicly available data on solar PV production profiles, installed DG capacity by utility and system load profiles.

INNOVATIVE RATE DESIGN AND IMPACT EVALUATION STUDIES

- For a gas and electric distribution utility in the Northeast, analyzed the operating cost of electric heat pumps and natural gas-fueled heating equipment, quantified the cost gap between the two types of equipment under alternative rate designs, and assisted in the development of rate designs to mitigate the cost gap. The study included estimation of the electric load impacts of electrification of a small sample of the utility's residential customers based on their historical gas usage, followed by calculation of their hypothetical future electricity bills under various rate structures. The utility is using insights from this study to appropriately size heat pump incentives and to mitigate the heat pump affordability barrier by marketing a beneficial rate structure to customers.

- Assisted with rate design proposal. Brattle has been retained by Nova Scotia power to assist with a comprehensive evaluation of innovative rate designs and development of Company's rate design proposal including load and bill impact analyses. Brattle team participated in stakeholder sessions to socialize the rate design with the stakeholders.
- Review of Rate Design Studies on Behalf of the Staff of the New Hampshire Public Utilities Commission. Brattle reviewed the rate design studies presented by Liberty Utilities and Eversource and filed testimony on behalf of the Staff. Both studies focused on the distribution services offered by the utilities and examined and testified on issues involving embedded and marginal cost based rate design. Dr. Sergici filed direct testimony in the proceeding.
- For CPS energy, prepared educational presentation materials for Rate Advisory Committee meetings. Prepared slide decks to explain concepts and methods in cost of service and rate design studies; summarized results from previous Brattle projects.
- Design, measurement and verification of Maryland Joint Utilities' PC44 TOU pilot. Brattle serves as the technical lead on behalf of the Maryland Joint Utilities, and led the pilot design and M&V methodology work streams in the PC44 workgroup process. Brattle will evaluate results from these three pilots in 2020.
- Assisted a New Zealand distribution utility with development of a peak time rebate pilot. Advised the client in pilot design principles and calculated sample sizes to yield statistically significant results. Undertook empirical testing of more than 150 different baseline methods using the client data and recommended an approach that leads to the highest accuracy and lowest bias in predicting the event day usage.
- Developed a model for the Ontario Energy Board to estimate a counterfactual hourly customer demand profile for multiple innovative pricing profiles of interest. Evaluated the economic efficiency of each alternative pricing option, taking into account system cost drivers including energy, ancillary services, generation capacity, and transmission and distribution capacity, as well as overall changes to consumer welfare driven by induced changes in demand. This represents one of few efforts to fully quantify the societal costs and benefits of innovative rate structures and involved close collaboration with the OEB team to ensure the Ontario-specific market structures were accurately reflected in our analysis.
- Technical Advisor to OEB on the New RPP Pilots. A Brattle team led by Dr. Sergici has developed a Technical Manual to guide the design and impact evaluation of new RPP pilots. Dr. Sergici has

been closely working with the OEB RPP team as they oversee the implementation of these pilots in accordance with the guidelines

- Undertook impact Evaluation of Ontario's Time-of-Use Rates on Behalf of Ontario Power Authority. A Brattle team led by Dr. Sergici provided an impact evaluation of Ontario's province-wide roll-out of Time-of-Use (TOU) rates for its residential and general service customers on behalf of Ontario Power Authority. Brattle acquired hourly load data from the IESO and the LDCs, aggregated it for the pricing periods that correspond to the TOU rate, reinterpreted the full-scale deployment as a natural experiment, and analyzed it using econometric methods for three consecutive years.
- Undertook a retail rate benchmarking study for a large southwestern utility. Our team, led by Dr. Sergici, reviewed utility resource plans to estimate each utility's retail rate trajectory. We compared the utilities across a variety of rate drivers, such as reserve margin, fuel mix, load growth, load factor, renewables investment requirements, and demand-side activities, and provided strategic recommendations for addressing these drivers of future rate growth.
- Undertook an extensive review of the rate designs and methodologies used by other jurisdictions/countries for a large Canadian Utility. We reviewed the rates that are currently offered by a large Canadian utility and compared them with best industry practices from around the globe. As a result of our analysis, we identify some near term and long term alternative rate design options for our client, which can help them to manage revenue risks and volatility due to the effects of disruptive threats, and at the same time to increase innovation and affordability in the rate options presented to the customers.
- Assisted Pepco Holdings, Inc. to evaluate the effectiveness of the AMI-enabled energy managements tools (EMTs) in reducing per capita energy use. Led a team of four researchers to compile and process data for four of the PHI jurisdictions; identify relevant control groups and methodology for impact evaluation and undertake an econometric analysis to quantify the EMT impact.
- Assisted an industry-leading provider of integrated demand response, energy efficiency, and customer engagement solutions in the design of and M&V plan for a behavioral demand response program. The plan included a detailed section on sampling selection for statistically valid and detectable program impact results.
- Prepared a comprehensive blueprint document for measuring the impacts of Baltimore Gas and Electric Company's Smart Grid Customer Programs. BGE has started deploying smart meters to all of its residential customers in Spring of 2012 and is scheduled to complete the deployment over a three-year period. BGE developed a full-scale program, "Smart Energy Manager (SEM)" program, to meet a central objective of the Smart Grid Initiative - customer education and engagement in a Smart Grid environment. The blueprint documented the design elements of

the SEM program and introducing the approaches that will be used to measure the impacts of different SEM tools once the program is in the field and sufficient data are collected.

- Measurement and evaluation for in-home displays, home energy controllers, smart appliances and alternative rates for FPL. Carried out a 2-year impact evaluation of a dynamic and enabling technology pilot program. Used econometric methods to estimate the changes in load shapes, changes in peak demand, and changes in energy consumption for three different treatments. The results of this study were shared with Department of Energy as to fulfill the data reporting requirements of FPL's Smart Grid Investment Grant.
- Pricing and technology pilot design and interim impact evaluation for Commonwealth Edison Company (ComEd). Assisted ComEd in the design of an ambitious pilot program that included approximately 25 different treatment cells. The pilot, which is the first "opt-out" pilot program of its kind, involved 8,000 customers and tested the impact of dynamic prices with and without customer education, informational feedback through basic and advanced feedback devices, and other enabling technologies in the summer of 2010. Conducted an interim impact evaluation study preceding the formal impact evaluation of the study, which is planned to be completed by the end of 2011.
- Pricing and technology pilot design and impact evaluation for Consumers Energy. Designed Consumers Energy's pricing and technology pilot and conducted the impact evaluation study after the pilot was completed in September 2010. The pilot tested critical peak pricing (CPP) and peak time rebates (PTR) in conjunction with information treatment and technology. The pilot also tested the potential "Hawthorne bias" for a group of control group customers who were aware of their involvement in the pilot.
- For an Independent System Operator (ISO), designed, managed and analyzed a market research to help improve participation in retail electricity products that encourage price-responsive demand (PRD). The research determined customer preferences for various time-based pricing products that would help define PRD products that may be developed in the ISO for each customer class. ISO will use the results of this research to assist in modifying wholesale market design to better support such PRD products.
- Assisted a client in conceptually developing a new product that would increase customer participation and performance in energy efficiency (EE) and demand response (DR) programs. Developed Total Resource Cost (TRC) tests for a few targeted EE and DR programs, and modeled the benefits and costs with and without the client's new product offering
- Co-authored a whitepaper reviewing the results from five recent pilot and full-scale programs that investigated low-income customer price-responsiveness to dynamic prices. The core finding of the whitepaper is that low income customers are responsive to dynamic rates and that many such customers can benefit even without shifting load.

- For a large California utility, conducted an econometric analysis, which investigated the role of weather conditions, smart meter installations, and electricity rate increases, among other control variables, in explaining the changes in the monthly usages and bills of a group of complaining customers. Estimated pooled regressions using a panel dataset, as well as individual customer regressions for more than 1,000 customers.
- Assisted an Illinois electric utility in the assessment of alternative baseline calculation for implementing peak time rebate (PTR) programs. Under a PTR program, participants receive a cash rebate for each kWh of load that they reduce below their baseline usage during the event hours. This requires establishment of a baseline load from which the reductions can be computed. The analysis involved simulating baselines for more than 2,000 customers using five alternative methodologies for several event days. Identified and recommended the baseline calculation methodology that yielded the most accurate baseline for individual customers, through the use of MAPE and RMSE statistics.
- Evaluated the Plan-It Wise Energy program (PWEP) of Connecticut Light and Power (CL&P) Company. PWEP tested the impacts of critical peak pricing (CPP), peak time rebates (PTR), and time of use (TOU) rates on the consumption behaviors of residential and small commercial customers. Each rate design was tested with high and low price variation as well as with and without enabling technologies. Conducted an econometric analysis to determine weather dependent substitution and daily price elasticities and subsequently quantified demand and energy impacts for each of the treatments tested in the PWEP. Developed optimal rate designs to be adopted in a full deployment scenario.
- For Baltimore Gas and Electric Company, assisted in the preparation of direct and rebuttal expert testimonies before the Maryland Public Service Commission, that explain the design and results of 2008 and 2009 Smart Energy Pricing (SEP) pilots.
- Evaluated the Smart Energy Pricing (SEP) pilot program of Baltimore Gas and Electric Company for three consecutive years. The pilot was designed to quantify the impacts of critical peak pricing (CPP) and peak time rebates (PTR) on residential customer consumption patterns. Conducted an econometric analysis to estimate demand systems and predict substitution and daily price elasticities for participating customers. Using the parameters of the demand equations, quantified demand, energy, and bill impacts associated with the programs. Impacts of the socio-demographic characteristics of the participants as well as their ownership of enabling technologies were separately identified on the demand response of the program participants.
- Co-authored a business practice manual for forecasting price responsive demand (PRD) in Midwest ISO. The draft manual introduces different methodologies for measuring and incorporating PRD into forecast LSE requirement for LSEs that are at different stages of rolling-

out their out their dynamic pricing programs. The draft manual also proposes methodologies for the verification of the forecasted demand net of PRD for long term planning purposes.

- Assisted in the development of an affidavit that evaluates the implications of PJM's proposed revisions to the Operating Agreement (OA) on barriers to participation in PJM's Economic and Emergency Load Response programs.
- Co-authored a whitepaper on "Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets" for Institute for Electric Efficiency. Whitepaper is intended to help facilitate nationwide progress toward the deployment of dynamic pricing of electricity by summarizing information that may assist utilities and regulators who are assessing the business case for advanced metering infrastructure (AMI).
- Assisted a New York utility in benchmarking their existing Demand Response (DR) portfolio to the best practice in U.S. and recommended improvements in their planned DR portfolio. Also assisted the utility in quantifying costs and benefits of pilot programs proposed in their DR filing before the State of New York Public Service Commission.
- Assisted an electric utility in developing a residential pricing pilot program that tests inclining-block rate (IBR) structure. More specifically, designed several revenue neutral IBR alternatives and quantified load reduction and bill impacts from these IBR rates.
- Assisted an electric utility in their dynamic rate design efforts. Conducted impact analyses of converting from a flat rate design to alternative dynamic rate designs for each of the five major customer rate classes of the utility. Developed models that allow simulation of energy, demand, and bill impacts by season, day type and time period for an average customer from each of customer classes.
- Simulated the potential demand response of an Illinois utility's residential customers enrolled in real time prices. Results of this simulation were used in recent Midwest ISO Supply Adequacy Working Group (SAWG) meeting to facilitate conversation about price responsive demand in the region. Simulations were run for different scenarios including historic versus spiky real-time prices; peak versus uniform allocation of capacity charges; and with and without enabling technologies.
- Designed a survey on Long-run Drivers of U.S. Energy Efficiency and Demand Response Potential on behalf of EPRI and EEI. Conducted statistical analyses to examine the survey responses, which were turned in by more than 300 power industry leaders and academic experts. Using the outcomes from this survey, assisted in the development of future scenarios to model energy efficiency and demand response impact through 2030.
- Assisted in the preparation of an EEI report that quantifies the benefits to consumers and utilities of dynamic pricing. Undertook a comprehensive review of the dynamic pricing programs

across the U.S. and elsewhere. Also implemented price response simulations to quantify the likely peak demand reductions that would realize under alternative dynamic pricing schemes.

UTILITY REGULATORY AND BUSINESS MODELS

- Assisted the New York Department of Public Service to develop a comprehensive financial model of a representative (downstate) New York utility capable of demonstrating the impacts of REV initiatives upon utility financial performance. Our modeling effort included developing plausible incentive regulation frameworks, new incentive mechanisms, and potential platform frameworks, services and futures.
- Development of Performance Incentive Metrics for the Joint Utilities of New York. The Brattle Group worked with the New York PSC Staff and, subsequently, with the State's six investor owned electric utilities (Joint Utilities) in analyzing the feasibility and impacts associated with proposed earnings sharing mechanisms (EAMs), primarily the EAMs associated with load factor and system efficiency.
- Assisted a North American Utility with development of a short-term and long-term regulatory strategy to enable their 2030 Vision. Brattle team interviewed the executive team; identified consensus views and disagreements on alternative business models and regulatory models. Developed straw proposals for two potential regulatory models one focused on enabling shorter-term outcomes, and the other focused on enabling Company's longer-term vision.
- Assisted Pepco D.C. as they develop a multi-year rate plan and various traditional and emerging performance incentive metrics to be filed in their upcoming rate case. Brattle team developed and facilitated workshops to introduce Pepco's MYRP proposal to the stakeholders and assisted Pepco with incorporating stakeholder input to the final proposal.
- Assisted a Canadian Utility with a critical assessment of their custom incentive ratemaking model and discussed how it compares with other forms of PBR. We presented a jurisdictional scan of the PBR implementations across North America and Europe, and assessed pros and cons of each approach. We also advised them on currently proposed "Distributed Utility Models" and assess pros and cons of each model; reviewed "Alternative Regulatory Models" that were developed to ensure that utilities can coexist with the DERs and continue to maintain healthy balance sheets.
- For a Canadian electric utility, reviewed and summarized alternative regulatory frameworks and incentive models that would support a sustainable energy efficiency business. Investigated the pros and cons of these models, identified the implications of each model for the utility, and made a recommendation based on our findings. Utility will discuss the recommended approach with the regulator and seek an approval.

- For a large Canadian electric utility, assisted with the development of an alternative proposal to their current performance based regulation (PBR) framework. Examined and benchmarked several examples of performance based regulation schemes in place for other utilities, and advised on an enhanced PBR mechanism.

DEMAND FORECASTING

- For an Asian utility considering an investment on a generation plant in PJM, we have reviewed, replicated, and developed alternative load forecasts using PJM's 2017 update. We have determined several uncertainty factors that are not fully captured in PJM's forecasting framework and developed "low load" and "high load" scenarios after accounting for these factors.
- For an electric utility in the Southeast, reviewed load forecasting models for residential and commercial customer classes. Assessed the accuracy and validity of the models by reviewing the historic and forecast period inputs to the model; model specification; in-sample and out-of-sample accuracy statistics; and incorporation of DSM impacts to the model, among many others. Also conducted an analysis using the U.S. Energy Information Administration's Annual Energy Outlook (AEO) data to determine the forecast errors during pre and post-recession periods.
- Developed a blueprint for integrating energy efficiency program impacts into the load forecasts for a Canadian Utility. This effort involved estimating the future impact of energy efficiency programs to be included in the load forecasts and developing price elasticity estimates that can be used to forecast the impact of the future changes in the price of electricity.
- Developed a load forecasting model for the pumping load of California State Water Project. Identified the main drivers of pumping load in major pumping stations. Through Monte Carlo simulations, quantified the uncertainty around load forecasts.
- Assisted in the preparation of testimony that evaluates the reasonableness of Florida Power and Light Co.'s total customer and monthly net energy for load (NEL) forecasting models. In addition to evaluating the methodology, also reviewed the reasonableness of the inputs used in the historic and forecast periods and assessed the soundness of ex-post adjustments made to the forecasts.
- Assisted PJM in the evaluation of its models for forecasting peak demand and re-estimated new models to validate recommendations. Predicted forecasting errors of the existing models and helped improving the forecast methodology by introducing the state-of-the art estimation techniques. Individual models were developed for 18 transmission zones as well as a model for the entire PJM system.

- Assisted a large utility in New York in understanding the decline in electric sales during the recent past and attributed the decline to a change in customer expectations of future income, based on declining consumer confidence that has been created by the lingering economic recession.
- Reviewed the structure of the Tennessee Valley Authority's energy sales forecasting models by sector, assessed the magnitudes of the price elasticities and the model specifications used to generate them, analyzed the ability of the models to generate a baseline forecast that could serve as a point of reference when evaluating the likely impacts and cost-effectiveness of a wide range of new energy efficiency and demand response programs.
- Developed a demand forecast model for one of the world's largest steam system operators. Estimated regression models to predict the price elasticities and switching behavior of different consumer classes. Also helped in the development of a model to forecast the impact of alternative steam tariffs on the consumption and switching patterns of consumers.

SELECTED WHITEPAPERS AND REPORTS

- *New Jersey Energy Master Plan Ratepayer Impact Study*, with G Kavlak, K Spees, R Janakiraman, prepared for New Jersey Board of Public Utilities, (2022)
- *The Customer Action Pathway to National Decarbonization*, with Ryan Hledik, Michael Hagerty, Ahmad Faruqui, and Kate Peters, prepared for Oracle (September 2021)
- *PC44 Time of Use Pilots: Year One Evaluation*, with Ahmad Faruqui, Nicholas E. Powers, Sai Shetty, and Jingchen Jiang, prepared for Maryland Joint Utilities (September 15, 2020)
- *Nova Scotia Utility and Review Board: Time-Varying Pricing Project Submission*, with Ahmad Faruqui, prepared for the Nova Scotia Power (June 30, 2020)
- *Getting to 20 Million EVs by 2030: Opportunities for the Electricity Industry in Preparing for an EV Future*, with Michael Hagerty and Long Lam, published by The Brattle Group, Inc. (June 2020)
- *Renewable Energy Policy Pathways*, with Judy Chang, Kasparas Spokas, Maria Castaner, and Peter Jones, prepared in collaboration with the REBA Institute (May 2020)
- *Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency*, with Samuel A. Newell, Michael Hagerty, Evan Cohen, Sang H. Gang, John Wroble, and Patrick S. Daou, prepared for PJM (March 17, 2020)
- *Energy Efficiency Administrator Models: Relative Strengths and Impact on Energy Efficiency Program Success,* with Nicole Irwin, prepared for Uplight (November 2019)

- *Incorporating Distributed Energy Resources into Resource Planning: Energy Efficiency*, with Ryan Hledik, D.L. Oates, Tony Lee, and Jill Moraski, prepared for EPRI (May 2019)
- *Status of DSM Cost Recovery and Incentive Mechanisms,* with Ahmad Faruqui, Elaine Cunha, and John Higham, prepared for Baltimore Gas & Electric (February 20, 2019)
- *Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates: Response to PC51 Request for Comments*, W. Zarakas, S. Sergici, P. Donohoo-Vallett, and N. Irwin, prepared for Joint Utilities of Maryland and filed in support of comments in PC51 for the Maryland Public Utilities Commission (March 29, 2019)
- *U.S. Alternative Regulatory Mechanisms: Scope, Status and Future,* with William Zarakas and Pearl Donohoo-Vallett, prepared for Baltimore Gas & Electric, Delmarva Power & Light and Pepco (February 19, 2019)
- *A Review of Pay for Performance (P4P) Programs and M&V 2.0*, with Heidi Bishop and Ahmad Faruqui, prepared for Commonwealth Edison (July 20, 2018)
- *Reviewing the Business Case and Cost Recovery for Grid Modernization Investments,* with Michelle Li and Rebecca Carroll, prepared for National Electrical Manufacturers Association (NEM) (2018)
- *Pepco Maryland In-Home Display Pilot Analysis*, with Ahmad Faruqui, prepared for Pepco (June 2017)
- *80x50 Energy Sector Model Assumptions and Results,* with Michael Kline and Pearl Donohoo-Vallett, prepared for the Mayor's Office of Sustainability (January 4, 2017)
- *Impact Evaluation of Pepco District of Columbia's Portfolio of Energy Management Tools,* with Ahmad Faruqui and Kevin Arritt, prepared for Pepco District of Columbia (October 2016)
- *Impact Evaluation of Delmarva Maryland's Portfolio of Energy Management Tools,* with Ahmad Faruqui and Kevin Arritt, prepared for Delmarva Maryland (April 2016)
- *Impact Evaluation of Pepco Maryland's Portfolio of Energy Management Tools,* with Ahmad Faruqui and Kevin Arritt, prepared for Pepco Maryland (January 2016)
- *Impact Evaluation of Pepco Maryland's Phase I Conservation Voltage Reduction (CVR) Program,* with Ahmad Faruqui and Kevin Arritt, prepared for Pepco Maryland (July 2015)
- *Analysis of Ontario's Full Scale Roll-out of TOU Rates – Final Study,* with Neil Lessem, Ahmad Faruqui, Dean Mountain, Frank Denton, Byron Spencer, and Chris King, prepared for Independent Electric System Operator (February 2016)

http://www.ieso.ca/Documents/reports/Final-Analysis-of- Ontarios-Full-Scale-Roll-Out-of-TOU-Rates.pdf

- *Comparative Generation Costs of Utility-Scale and Residential Scale PV in Xcel Energy Colorado's Service Area,* with Bruce Tsuchida, Bob Mudge, Will Gorman, Peter Fox-Penner and Jens Schoene (EnernNex), prepared for First Solar (July 2015)
- *Quantifying the Amount and Economic Impacts of Missing Energy Efficiency in PJM's Load Forecast,* with Ahmad Faruqui and Kathleen Spees, prepared for The Sustainable FERC Project (September 2014)
- *Assessment of Load Factor as a System Efficiency Earning Adjustment Mechanism*, with William Zarakas, Kevin Arritt, and David Kwok, prepared for The Joint Utilities of New York (February 2017)
- *Expert Declaration in a Patent Dispute Case involving a Demand Response Product* (July 2014)
- *Measurement and Verification Principles for Behavior-Based Efficiency Programs,* with Ahmad Faruqui, prepared for Opower (May 2011) http://opower.com/uploads/library/file/10/brattle_mv_principles.pdf
- *Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets,* with Ahmad Faruqui and Lisa Wood, IEE Whitepaper (June 2009)
- *The Impact of Dynamic Pricing on Low Income Customers,* with Ahmad Faruqui and Jennifer Palmer, IEE Whitepaper (June 2010)

ARTICLES & PUBLICATIONS

- Retail Pricing: A Low-Cost Enabler of the Clean Energy Transition, with Long Lam, *IEEE Energy and Power Magazine*, July 2022
- "Bridging the Chasm between Pilots and Full-Scale Deployment of Time-of-Use Rates," *The Electricity Journal*, Volume 33, Issue 10 (December 2020)
- "Top Performing States in Energy Efficiency: Top States' Secret Sauce," *Public Utilities Fortnightly* (March 2020)
- "Quantifying Net Energy Metering Subsidies," with Yingxia Yang, Maria Castaner, and Ahmad Faruqui, *The Electricity Journal*, Volume 32, Issue 8 (October 2019)
- "Arcturus 2.0: A Meta-analysis of Time-varying Rates for Electricity," with Ahmad Faruqui and Cody Warner, *The Electricity Journal*, Volume 30, Issue 10 (December 2017)

- “Do Manufacturing Firms Relocate in Response to Rising Electric Rates?” with Ahmad Faruqui, *Energy Regulation Quarterly*, Volume 5, Issue 2 (June 2017)
- “Dynamic Pricing Works in a Hot, Humid Climate,” with Ahmad Faruqui and Neil Lessem, *Public Utilities Fortnightly* (May 2017)
- “The impact of AMI-enabled conservation voltage reduction on energy consumption and peak demand,” with Kevin Arritt and Sanem Sergici, *The Electricity Journal*, 30:2, pp. 60-65 (March 2017) http://www.sciencedirect.com/science/article/pii/S1040619016302536
- “Integration of residential PV and its implications for current and future residential electricity demand in the United States,” with Derya Eryilmaz, *The Electricity Journal*, 29, 41-52 (2016)
- “Impact Measurement of Tariff Changes when Experimentation is not an Option – A case study of Ontario, Canada,” with Neil Lessem and Dean Mountain, *Energy Economics*, 52, pp. 39-48 (December 2015)
- “Utility Investments in Resiliency: Balancing Benefits with Cost in an Uncertain Environment,” with William Zarakas, *et al*., *The Electricity Journal*, Volume 27, Issue 5 (June 2014)
- “Low Voltage Resiliency Insurance: Ensuring Critical Service Continuity during Major Power Outages,” with William Zarakas and Frank Graves, *Public Utilities Fortnightly* (September 2013)
- “Arcturus: International Evidence on Dynamic Pricing,” with Ahmad Faruqui, *The Electricity Journal*, 26:7, pp. 55-65 (August/September 2013)
- “Dynamic Pricing of Electricity for Residential Customers: The Evidence from Michigan,” by Ahmad Faruqui, Sanem Sergici and Lamine Akaba, *Energy Efficiency*, 6:3, pp. 571–584 (August 2013)
- “Dynamic Pricing of Electricity in the Mid-Atlantic Region: Econometric Results from the Baltimore Gas and Electric Company Experiment,” with Ahmad Faruqui, *Journal of Regulatory Economics*, 40(1), pp. 82–109 (2011)
- “The Untold Story of: A Survey of C&I Dynamic Pricing Pilot Studies,” with Ahmad Faruqui and Jenny Palmer, *Metering International*, Issue 3 (2010)
- Divestiture policy and operating efficiency in U.S. electric power distribution," with John E. Kwoka, Jr., and Michael Pollitt, *Journal of Regulatory Economics* (June 2010)

- “Household Response to Dynamic Pricing of Electricity – A Survey of the Experimental Evidence,” with Ahmad Faruqui, *Journal of Regulatory Economics* (October 2010)
- “Rethinking Prices,” with Ahmad Faruqui and Ryan Hledik, *Public Utilities Fortnightly* (January 2010)
- “Piloting the Smart Grid,” with Ahmad Faruqui and Ryan Hledik, *The Electricity Journal* (August/September 2009)
- "The Impact of Informational Feedback on Energy Consumption - A Survey of the Experimental Evidence," with Ahmad Faruqui and Ahmed Sharif, *Energy-The International Journal* (August 2009)
- “Three Essays on U.S. Electricity Restructuring,” Unpublished Ph.D. Thesis, Northeastern University (August 2008)

PRESENTATIONS & SPEAKING ENGAGEMENTS

- “Emerging Technologies and Tools for the Future,” presentation at the 8th Annual Grid Modernization Forum (June 2023)
- “Electricity Retail Rates to Facilitate Electrification,” presentation at the MIT Future Energy Systems Center Spring 2023 Workshop (June 2023)
- “Developing Innovative Rates for Accelerating the EV Transition,” presentation for the DOE EVGrid Assist Team (January 2023)
- “Heat-pump Friendly Cost-Based Rate Designs,” presentation at the 2022 NARUC Meeting (November 2022)
- “High Priority Areas for Accelerating EV Transition, “ presentation at the 2022 NARUC Meeting (November 2022)
- “Modernizing the Grid,” presented at the MIT Energy Conference (March 2022)
- “A New Approach to Strategic Planning in a High Distributed Resource Environment: Distributed Solar as a Case Study,” Next-Gen Smart Grid Virtual Summit (December 9, 2020)
- “What Explains the Success of Top Performing States in Energy Efficiency?” NRRI Webinar (August 19, 2020)
- “A Blueprint to Pilot Design: Best Practices and Lessons Learned,” MI Power Grid: Energy Programs and Technology Pilots Stakeholder Meeting (April 30, 2020)

- “Policies in Support of Customers’ Purchase of Renewable Energy,” NARUC Annual Meeting & Education Conference (November 18, 2019)
- “Rate Reform in Evolving Energy Marketplace,” EUCI Residential Demand Charges/TOU Summit (May 30, 2019)
- “Grid Modernization: Policy, Market Trends and Directions Forward,” 4th Annual Grid Modernization Forum, Chicago, IL (May 21, 2019)
- “Accelerating the Renewable Energy Transformation: Role of Green Power Tariffs and Blockchain,” EUCI Southeast Clean Power Summit (February 25, 2019)
- “The Case for Alternative Regulation and Unintended Consequences of Net Energy Metering,” 46th Annual PURC Conference, Gainesville, FL (February 21, 2019)
- “Reviewing Grid Modernization Investments: Summary of Recent Methods and Projects,” National Electrical Manufacturers Association (NEMA) (December 4, 2018)
- “Enabling Grid Modernization Through Alternative Rates and Alternative Regulation,” Energy Policy Roundtable in the PJM Footprint (November 29, 2018)
- “Return of Pay-for-Performance Stronger with M&V 2.0,” BECC Conference, Innovations in Models, Metrics, and Customer Choice, Washington DC (October 2018)
- “Rate Design in a High DER Environment,” MEDSIS Rate Design Workshop, Washington DC, (September 2018)
- “Demand Response for Natural Gas Distribution,” Center for Research in Regulated Industries (CRRI) 31st Annual Western Conference, Monterey CA (June 2018)
- “Status of Restructuring: Wholesale and Retail Markets,” National Conference of State Legislatures Workshop, "Electricity Markets and State Challenges," Indianapolis IN (June 2018)
- “Dynamic Pricing Works in a Hot and Humid Climate: Evidence from Florida,” International Energy Policy & Programme Evaluation Conference, Bangkok Thailand (November 2017)
- “Understanding Residential Customer Response to Demand Charges: Present and Future,” EUCI Residential Demand Charges Conference, Chicago IL (October 2016)
- “Utility Leaders Workshop: An Evolving Utility Business Model for the Caribbean,” Caribbean Renewable Energy Forum, Miami FL (October 2016)
- “Impact of Residential PV Penetration on Load Growth Expectations,” AEIC Western Load Research Conference, September 2016.

- "Moving away from Flat Rates," Smart Grid Consumer Collaborative, Chicago, IL (September 2016)
- "Residential Demand Charges: An Overview," EUCI Demand Charge Conference, Phoenix AZ (June 2016)
- "Conservation Voltage Reduction Econometric Impact Analysis," AESP Spring Conference, Washington DC (May 2016)
- "Caribbean Utility 2.0 Workshop- Economics, Tariffs and Implementation: The Challenge of Integrating Renewable Resources and After Engineering Solutions," co-hosted and presented at the Caribbean Renewable Energy Forum, Miami FL (October 2015)
- "Dispelling Common Residential DR Myths," eSource Conference (October 2015)
- "Low Income Customers and Time Varying Pricing: Issues, Concerns, and Opportunities," NYU School Law's Forum on New York REV and the Role of Time Varying Pricing (March 2015)
- "Dynamic Pricing: Transitioning from Experiments to Full Scale Deployments," EDF Demand Response Workshop, Paris, France (July 2014) and Governors Association's Michigan Retreat on Peak Shaving to Reduce Wasted Energy (August 2014)
- "Impact Evaluation of TOU Rates when Experimentation is not Option: A Case Study of Ontario, Canada," 2014 Smart Grid Virtual Summit, Boston (June 2014)
- "Residential Demand Response Opportunities," Opower Webinar Series, Boston (June 2014)
- "Impact Evaluation of TOU Rates when Experimentation is not Option: A Case Study of Ontario, Canada," 33rd Annual Eastern CRRI Conference (May 2014)
- "The Arc of Price Responsiveness—Consistency of Results Across Time-Varying Pricing Studies," Chartwell Webinar, Boston (May 2013)
- "Evaluation of Baltimore Gas and Electric Company's Smart Energy Pricing Program," 9th International Industrial Organization Conference, Boston, MA (April 2011)
- "Dynamic Pricing: What Have We Learned?" Electricity Markets Initiative Conference, Harrisburg, PA (April 2011)
- "Do Smart Rates Short Change Customers," Demand Resource Coordinating Committee Webinar (December 2010)
- "Opening Remarks and Session Chair of Day 1," FRA Conference on Customer Engagement in a Smart Grid World, San Francisco, CA (December 2010)

- “The Impact of Informational Feedback on Energy Consumption,” 2010 National Town Meeting on Demand Response and Smart Grid (June 2010)
- “The Impact of In-Home Displays on Energy Consumption,” Colorado Public Service Commission (June 2010)
- “Does Dynamic Pricing Work in the Mid-Atlantic Region: Econometric Analysis of Experimental Data,” Center for Research in Regulated Industries (CRRI) 29th Annual Eastern Conference (May 2010)
- “Distributed Generation in a Smart Grid Environment,” panel speaker at the Center for Research in Regulated Industries (CRRI) 29th Annual Eastern Conference (May 2010)
- “Power of Information Feedback: A Survey of Experimental Evidence,” Peak Load Management Alliance (PLMA) Webinar (April 2010)
- “Customer Response to Dynamic Pricing - A Long Term Vision,” 2009 NASUCA Mid- Year Meeting, Boston (June 2009)
- “BGE’s Smart Energy Pricing Pilot Summer 2008 Impact Evaluation,” Association of Edison Illuminating Companies (AECI) Conference, Florida (May 2009)
- "California and Maryland - Are They Poles Apart?," Western Load Research Association Conference, Atlanta (March 2009)
- “Experimental Design Considerations in Evaluating the Smart Grid," Smart Grid Information Session Massachusetts DPU (December 2008)
- “Divestiture, Vertical Integration, and Efficiency: An Exploratory Analysis of Electric Power Distribution,” 4th International Industrial Organization Conference, Boston, Massachusetts (2006)

Exhibit 7: Report on National Grid's ESMP proposal by 1898 & Co

PART OF BURNS & McDONNELL

A REVIEW OF THE DRAFT NATIONAL GRID ELECTRIC SECTOR MODERNIZATION PLAN

PROJECT 160413

REVISION 0

August 30, 2023

Disclaimer

CONTENTS

Introduction

Nature of Engagement

National Grid (Company) sought external technical knowledge and experience to review the development of the Electric Sector Modernization Plan (ESMP), assess the reasonableness of the portfolio of proposed investments considering industry practices and available solutions, and opine on any investments that may be missing from the plan given the Commonwealth's goals and any solutions that might be seen as overbuilding. National Grid retained 1898 & Co. to review the draft ESMP that is to be submitted to the Massachusetts Grid Modernization Advisory Council on September 1, 2023, and evaluate the following:

1) Alignment of the draft ESMP to the Commonwealth's 2050 Net Zero goals, customer expectations, and National Grid electric business strategy, and
2) Alignment of forecasting, planning, and estimating approaches and methodologies and the proposed ESMP solutions with electric utility practices.

The Statement of Work, mutually executed on July 11, 2023, tasked 1898 & Co. to consider the following questions and prepare a brief opinion letter with our observations and conclusions.

Key Questions

- *Is the ESMP aligned with the internal Electric Business Strategy, the Responsible Business Charter, the Commonwealth's policy goals, and our customers' needs/expectations?*
- *Does National Grid's plan have the right investments at the right pace (i.e., won't be a blocker but will have "used and useful" investments), and is it coherent (the interactions are identified and being managed)?*
- *Do the Company's proposed network investments account for the impacts on electricity demand from energy efficiency, beneficial electrification, distributed energy resources (e.g., solar PV, energy storage, demand response), and other load flexibility aligned with electric utility industry best practice?*
- *Does the Company's digital solutions and OT/telecommunications provide a suitable roadmap to delivering customer value while minimizing network investments?*
- *Does the plan accurately account for the Commonwealth's clean energy and climate policy goals and align with the overall progression towards the 2050 outcomes?*
- *Do the Company's distribution area studies provide a reasonable, robust, and reliable view of how customer demand will grow considering anticipated economic conditions and Commonwealth clean energy policy goals?*
- *Is the Company's methodology for allocating system-level load growth to distinct planning areas of its network robust including prioritization of the needs?*
- *Does the Company's plan incorporate the necessary capabilities and are the capabilities aligned with the direction of the 'state of the art' in the electric utility industry?*

Approach

1898 & Co. reviewed iterations of the draft Electric Sector Modernization Plan and other data and informational materials provided by National Grid. We had discussions with National Grid staff to clarify our understanding of the provided materials and proposed investments. Through the course of the engagement, we provided observations and feedback to National Grid regarding the reasonableness and completeness of the drafts of the ESMP based on 1898 & Co. experiences working with other utilities on similar distribution system modernization and digital transformation initiatives. We supplemented our experience with reviews of publicly available literature and data on other utility investment plans to support policies and goals like those of the Commonwealth.

The opinion shared for each of the questions in the following section, *Commentary on Key Questions,* reflect the results of our observations from the review and assessment of iterations of the drafting of the ESMP in preparation for submission to the Massachusetts Grid Modernization Advisory Council on September 1, 2023, and supporting details made available by National Grid. Our observations broadly focus on National Grid's proposed distribution system investments (network and technology) with a focus on the methodologies and approaches to identify investments that will support Commonwealth goals and customer expectations. We reviewed the National Grid's plan and available supporting information including general assumptions, demand forecasts, proposed technologies, and samples of associated cost estimates for reasonableness and completeness but did not perform any independent analyses to affirm the accuracy of the portfolio or individual solution cost estimates or implementation assumptions and timelines. Further, National Grid's ESMP is based on current Commonwealth, and where applicable federal, policies and goals; any changes in scope or timeline to these or introduction of any new policies and goals may affect National Grid's forecasts and proposed investments. Our conclusions regarding National Grid's approach to developing the ESMP and the plan's alignment with electric utility industry trends and accepted practices are based on experience working with other U.S. electric utilities.

Summary of Qualifications

1898 & Co.

1898 & Co. is a global business and technology consultancy that delivers strategic business insights and solutions for critical infrastructure industries. We serve power and utility clients of all sizes across the U.S. We provide services and experience in electric transmission and distribution planning; utility investment planning; grid modernization; technology strategy, assessments, and implementation; and cybersecurity.

Consultants

The following 1898 & Co. consultants contributed to the review of the draft Electric Sector Modernization Plan and this report.

Lucas McIntosh is an 1898 & Co. Managing Director and leads our Power Grid Advisory Practice. He has contributed to and developed grid modernization roadmaps and components for numerous investor-owned utilities.

Doug Houseman is an 1898 & Co. Principal Consultant with 46 years of experience and is a leader in grid modernization thinking. He has authored significant portions of the IEEE's GridVision 2050 and the DOE's QER, as well as revisions to the Centre for Energy Advancement through Technological Innovation (CEATI) Distribution Utility Technology Roadmap. Doug is a National Institute for Standards and Technology (NIST) Fellow and emeritus member of the GridWise Architecture Council (GWAC) where he had a hand in both the Smart Grid Interoperability Maturity Model and Transactive Energy. He has developed more than twenty tutorials for grid modernization for IEEE and others.

Mark Knight is an 1898 & Co. Principal Consultant with more than 35 years of experience in strategy and asset management across multiple critical infrastructure industries. He is a Fellow of the Institute of Asset Management and Chair of the Coasts, Oceans, Ports and River's Institute (COPRI) Resilient and Sustainable Port Development, Operations, and Maintenance Subcommittee (part of COPRI's asset management task force). Mark was formerly Chairman of the GridWise Architecture Council, and the Administrator for the Council where he coordinated planning and budget with the Department of Energy. Mark was also the Chair of the Smart Electric Power Alliance (SEPA) Transactive Energy Working Group. Prior to joining 1898 & Co. he was a chief engineer at one of the U.S. national laboratories working on grid modernization research.

Kevin Huff is an 1898 & Co. Senior Consultant with nearly 30 years of experience working at a public utility managing the integration of information, operational, and engineering technologies. He co-authored an initial distribution enablement plan (Grid Mod), and as a grid modernization leader, he implemented a program management office to execute the plan and established an innovation program and physical lab. His experience helps clients accelerate their plans effectively.

Nathan Brown is an 1898 & Co. Senior Consultant with more than 20 years of experience leading large technology transformation projects across the utility and infrastructure sectors by designing then driving innovative and efficient strategies, roadmaps, and solutions to fit with a specific organization capability while meeting operational system objectives.

Gregory A. Player is an 1898 & Co. Director with 14 years of experience in project management and consulting for electric and gas utilities. As a project manager, working at a New Jersey investor-owned utility, Greg led large electric transmission and distribution reliability projects. More recently as a consultant, he has supported deployment of advanced metering (electric and gas), and technology and data and analytics initiatives for grid modernization and customer care.

Commentary on Key Questions

Is the ESMP aligned with the internal Electric Business Strategy, the Responsible Business Charter, the Commonwealth's policy goals, and our customers' needs/expectations?

While required by the Massachusetts Climate Law 2022, the Electric Sector Modernization plan (ESMP) reflects the broader National Grid strategy to enable reductions in greenhouse gas emissions (GHG) while maintaining and operating a reliable, resilient, and flexible electric distribution system. Like the Commonwealth, National Grid envisions achieving net-zero by 2050. The National Grid U.S. net zero plan[1], Responsible Business Charter[2], and clean energy vision[3], each articulate strategies to reduce GHG emissions through energy efficiency and demand response, decarbonization of transportation and heating, and interconnection of renewable generation (e.g., solar, offshore wind). The adoption of decarbonization technologies by both National Grid and Massachusetts customers and increased interconnection of clean energy resources will depend on a flexible and capable network infrastructure, modern digital solutions to safely monitor and manage dynamic power flows, and customer engagement in innovative programs.

The ESMP is a logical next step in the National Grid electric business strategy that builds on the foundation of programs previously authorized and approved by the Department of Public Utilities (D.P.U.). Programs such as Energy Efficiency/Demand Response, Grid Modernization, AMI, and Electric Vehicle are improving system reliability, accommodating DERs, and enabling customers to use energy more efficiently and adopt decarbonization technologies.

[1] https://www.nationalgrid.com/us/net-zero-plan
[2] https://www.nationalgrid.com/document/134426/download
[3] https://www.nationalgrid.com/document/146251/download

Does National Grid's plan have the right investments at the right pace (i.e., won't be a blocker but will have "used and useful" investments), and is it coherent (the interactions are identified and being managed)?

National Grid plans to have investments in the right places at the right times that account for the projected long-term (e.g., 2050) needs. National Grid evaluated electric demand projections through 2050 to identify when and where network capacity is needed and provide sufficient runway to plan, engineer, and construct network solutions that are "used and useful" beyond the 5- and 10-year planning horizons. In planning the ESMP investments, National Grid also considered its core investment workplans as well as those to support new customer load and distributed generation interconnection requests. While the actual timing of projects is dependent on several factors, National Grid reasonably assumes that infrastructure upgrades included in the base investment plans, pending CIPs[4], and other known and studied customer and distributed generation interconnection projects would be in place, thus the resulting ESMP investments are incremental and timed to support projected peak electric demand growth attributable to electrification. National Grid is trying to be flexible in where they make investments as the customers make decisions on where to place solar and storage, when to purchase electric vehicles and adopt heating electrification. Changes in Federal policy and subsidies may accelerate or slow customer decisions. New Commonwealth policies may also change current forecasts.

One concern is getting behind on investments, as there are limited options in the market today for equipment and labor to complete large projects faster than planned. Manufacturing lead times for transformers and other equipment may result in a three-to-five-year gap between planning and the start of construction. Most U.S. utilities are reporting limits on their engineering staff and construction resources (both internal and external), which if pushed to accelerate projects may be further strained putting workplans at risk.

The pacing of National Grid's network investments for the 5- and 10-year solution sets was first based on identification and prioritization of needs through 2034, while also considering forecasted impacts from projections in the 2034 to 2050 period. National Grid then evaluated each solution for deliverability. The deliverability evaluation considered the magnitude and complexity of each infrastructure solution, such as the installation of new transformer in an existing substation compared to construction of a new substation that will require land acquisition and new transmission taps. National Grid adjusted the pace of investment to account for procurement, land acquisition, and permitting timelines. If the prioritization and pacing of investments resulted in a gap of a local capacity need by date and a long-term solution in-service date, National Grid has accounted for non-wire alternatives to temporarily manage system capacity until long-term solutions are complete.

The scheduled five-year reviews and update of the ESMP will provide an opportunity to reevaluate the 10-year and beyond needs and solutions based on realized trends in adoption and any updates to projections. This may result in investment deferments, reprioritization, or changes in solution scopes. These reviews will be important to adjusting investments and timing. Studies by utilities such as Baltimore Gas & Electric (BGE), Con Edison, First Energy, and DTE Energy show that load growth may exceed 220% by 2050 on specific circuits. The studies also show that minor changes in the rate of customer investments can change utility investment timing by as much as a decade. As no utility has a crystal ball, regular review and adjustments of forecasts are necessary to account for customer behaviors.

[4] CIP = Capital Investment Plans. National Grid has proposed several capital investments needed to interconnect solar and energy storage projects in specific planning areas that are pending D.P.U. approval. The ESMP assumes that the Company's CIP proposals are approved.

Do the Company's proposed network investments account for the impacts on electricity demand from energy efficiency, beneficial electrification, distributed energy resources (e.g., solar PV, energy storage, demand response), and other load flexibility aligned with electric utility industry best practice?

National Grid's approach to forecast and identify network upgrade investments aligns with industry practices to proactively prepare for the impacts from electrification while also accounting for potential reductions in demand through energy efficiency and demand response programs, as well as customer-sited solar and energy storage. National Grid assessed historical electric demand and projected future annual peak demand and hourly load profiles over multiple scenarios and identified a most likely case for each. The impacts on the current distribution system from the projections were evaluated using the National Grid engineering planning criteria, which is an established standard to identify when network investment is necessary and how to appropriately scope a solution that addresses one or more needs (e.g., capacity, reliability). To address the expected peak demands from increased electricity traffic due to electrification and DERs over the next several decades, the primary and most significant investment will be in distribution system infrastructure such as feeder and substation upgrades and the construction of new feeders and substations. This is approach is common among utilities for determining how and when to upgrade or expand the distribution system.

The expected volume of network investment for National Grid to prepare its distribution system for electrification, DERs, and the interconnection of renewables is comparable to utilities in states like New York and California that have policies and goals on a similar scale and timeline to Massachusetts. For comparison, Con Edison projects to spend approximately $4.2 billion on system needs to support load growth from electrification, including over 35,000 service upgrades in the next decade to connect electric vehicles and electric heat pumps, and accommodate increased DER penetration.[5] Similarly, an independent assessment of the investment needs in Northern California to accommodate residential electrification (i.e., space and water heating) and electric vehicle adoption estimates an additional $1 billion to potentially over $10 billion to PG&E's rate base. The researchers found that a significant number of the three thousand PG&E circuits are expected to need upgrades under various scenarios by 2030, and that the number of necessary substations upgrades increases over time.[6] As more clean energy policies, goals, and subsidies are introduced, utilities will need to invest significantly in their distribution systems to accommodate the load increases expected from electrification.

Does the Company's digital solutions and OT/telecommunications provide a suitable roadmap to delivering customer value while minimizing network investments?

The National Grid digital solutions (e.g., products, platforms), operational technology (OT), and telecommunication components represent a logical approach to supporting the proposed investments detailed within the ESMP. National Grid's plan lays out a direction supporting electrification, decarbonization, and enhanced customer experiences that requires additional investments in technology. National Grid has detailed the need to enhance systems, systems integration, data utilization, communication networks, cybersecurity, and customer energy management and portal solutions. This is consistent with Commonwealth goals and the other proposed investments in the ESMP.

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[5] Consolidated Edison Company of New York, Inc. "A Comprehensive View of Our Electric System through 2050". January 2022. <https://cdne-dcxprod-sitecore.azureedge.net/-/media/files/coned/documents/our-energy-future/our-energy-projects/electric-long-range-plan.pdf?rev=bbf28eccf40a47f093021af02c278d39&hash=0D678FF3CF1B599B0DAAC9D223C9487C>

[6] Salma Elmallah et al 2022 Environ. Res.: Infrastruct. Sustain. < https://iopscience.iop.org/article/10.1088/2634-4505/ac949c>

To support grid planning and distribution operations, further investments in sensors, communications, and operational technology requires additional investment such as:

- Further develop and utilize ADMS/DERMS platform to optimize (monitor and control) the value of distributed energy resources and the grid that enables them.
- Reengineer data management solutions to streamline the collection, classification, storage, flow, and analysis of data to enable a diverse set of business requirements.
- Enhance existing communication networks to ensure that headend systems like EMS, ADMS, and DERMS can communicate timely and reliably with sensing and control devices on the grid.
- Bolster cybersecurity standards, processes, and tools to reduce cyber intrusion risk.

National Grid outlines in the ESMP reasonable investments in areas such as advanced metering infrastructure (previously approved and in progress), customer energy management, and customer portals to provide a better overall customer experience. These investments align with and will support the expectations of the Commonwealth to prioritize deployment of energy efficiency, time varying-rates, and other load flexibility measures.

Overall, National Grid's plan for digital solutions and OT/telecommunication components aligns with investments we are seeing across the electric utility industry. Foundational technologies such as communication networks, cybersecurity, and data management investments are a priority as enablers of advanced digital grid operations and capabilities.

Does the plan accurately account for the Commonwealth's clean energy and climate policy goals and align with the overall progression towards the 2050 outcomes?

National Grid's developed their plan by working back from the Commonwealth's 2050 target GHG emissions in the transportation, buildings, and electric power sectors. The plan accounts for the forecasted adoption rates for electric vehicles, electric heat pumps, energy efficiency, energy storage, renewable energy generation and similar technologies in National Grid's service territory that are necessary to support achieving the Commonwealth's goals. National Grid has prepared a plan that accounts for the significant impacts expected over the next 10 years. Their plan supports a doubling of distributed solar interconnection, fifteen times the number of electric vehicles, and fourteen times the number of electric heat pumps compared to today.

The progression to achieving the 2050 outcomes depends on economic, regulatory, customer behaviors and other factors. State and federal policy, regulations, queue times, subsidies, and changes in costs will determine what renewable generation will be built, where, and how fast. The availability of electric vehicles and required charging infrastructure plus costs (purchasing, charging, maintenance, etc.) will drive customer adoption. No one can fully anticipate the rate of change. For instance, in 2019 utilities were forecasting increased sales of electric vehicles, but not the witnessed 48% rise in second quarter of 2023.[7] Anticipation is now that electric vehicle sales will exceed one-million vehicles in 2023 and may double that in 2024. As mentioned previously, the scheduled 5-year plan reviews will be important to adjusting the plan to account for realized progression towards the 2050 outcomes.

[7] https://www.cnn.com/2023/08/20/cars/electric-cars-sales-gas-cars-dg/index.html#:~:text=Americans%20bought%20more%20electric%20vehicles,June%202023%20%E2%80%94%20a%20new%20record.&text=Not%20only%20is%20that%20more,sold%20in%20all%20of%202019

Do the Company's distribution area studies provide a reasonable, robust, and reliable view of how customer demand will grow in light of anticipated economic conditions and Commonwealth clean energy policy goals?

National Grid uses a structured and systematic approach to evaluate and plan for demand growth in each of its planning sub-regions that accounts for Commonwealth clean energy policy goals and local economic conditions. In its plan, National Grid discusses micro- and socioeconomic considerations for each planning sub-region and how these will influence load growth and adoption projections for electric vehicles, heat pumps, and DERs. For example, new electric heat pump projections are highest in the Central and Western sub-regions where most customers rely on delivered fuel oil and propane for heating. In contrast, the adoption projections are moderate in the Merrimack Valley sub-region given lower customer dependency on fuel oil and propane. Similarly, National Grid projected differences in electric vehicle adoption. For example, the South Shore sub-region is projected to see the most significant adoption of all types of electric vehicles due to the number of medium to high-income households and the large number of commercial customers, whereas in contrast, moderate electric vehicle adoption is projected for the Western sub-region given its rural nature. Overall, National Grid's distribution area studies provide a reasonable view and accounts for how demand may grow given current economic conditions and projections to support Commonwealth clean energy goals.

Is the Company's methodology for allocating system-level load growth to distinct planning areas of its network robust including prioritization of the needs?

National Grid's distribution area studies assessed multiple scenarios of demand growth across its service territory. National Grid forecasts the peak energy demands for its two Massachusetts service companies and the three ISO-NE zones in the state. This methodology allows for zonal forecasts in relation to system-level forecasts and analyze zonal specific economics when zonal and system-level growth are not in sync (e.g., zonal load growth occurring faster than system-level load growth). National Grid expects to see varying timing and levels of load growth across its service territory, which correlates to the identification, timing, and prioritization of network needs in each of the planning areas based on current regulatory conditions. National Grid will need to reforecast if those conditions change, which is part of its standard practice.

Does the Company's plan incorporate the necessary capabilities and are the capabilities aligned with the direction of the "state of the art" in the electric utility industry?

National Grid's vision is for its electric networks to be an integrated, intelligent, and customer centric platform that will enable the energy transition. As discussed previously, National Grid has detailed the necessary investments to enable advanced digital capabilities of grid planning and grid operations that is in alignment with the direction of the electric utility industry, especially those serving communities with accelerated transition policies. The proposed capabilities in the next 5- and 10-years will improve network planning, construction, and operations, enable customers, and optimize the value of distributed energy resources.

Conclusions

National Grid has prepared a plan that is in alignment with the Commonwealth's clean energy policies and proposes reasonable investments to achieve policy goals. Given the forecasted increases in peak demand and bi-directional energy flows on National Grid's distribution and substation infrastructure expected from broad adoption of electrification and DERs associated with the Commonwealth's net zero goals, the investments included in National Grid's ESMP are appropriate. Due to the pace and scale of these changes combined with limitations in resources to design and construct infrastructure upgrades, National Grid is appropriately planning to proactively ready its electric network to meet the needs of its customers and their communities in a period that supports these objectives. We believe National Grid has shown prudency in identifying these upgrades, evaluating deliverability, and sequencing the investments so that each is "used and useful."

Likewise, National Grid has proposed digital solutions and OT/telecommunications investments that align with the direction of these infrastructure investments and the electric utility industry. These digital solutions and networks will enable advanced capabilities to improve grid planning and operations, incentivize adoption and optimize the value of DERs, and enhance the customer experience.

We expect the 5-year review and calibration of these investments to realized adoption rates and changes to power flows will enable National Grid and the Commonwealth to adjust the timing and scale of subsequent investments to ensure electric infrastructure and digital operations align with customer needs while maintaining safety and affordability for customers.

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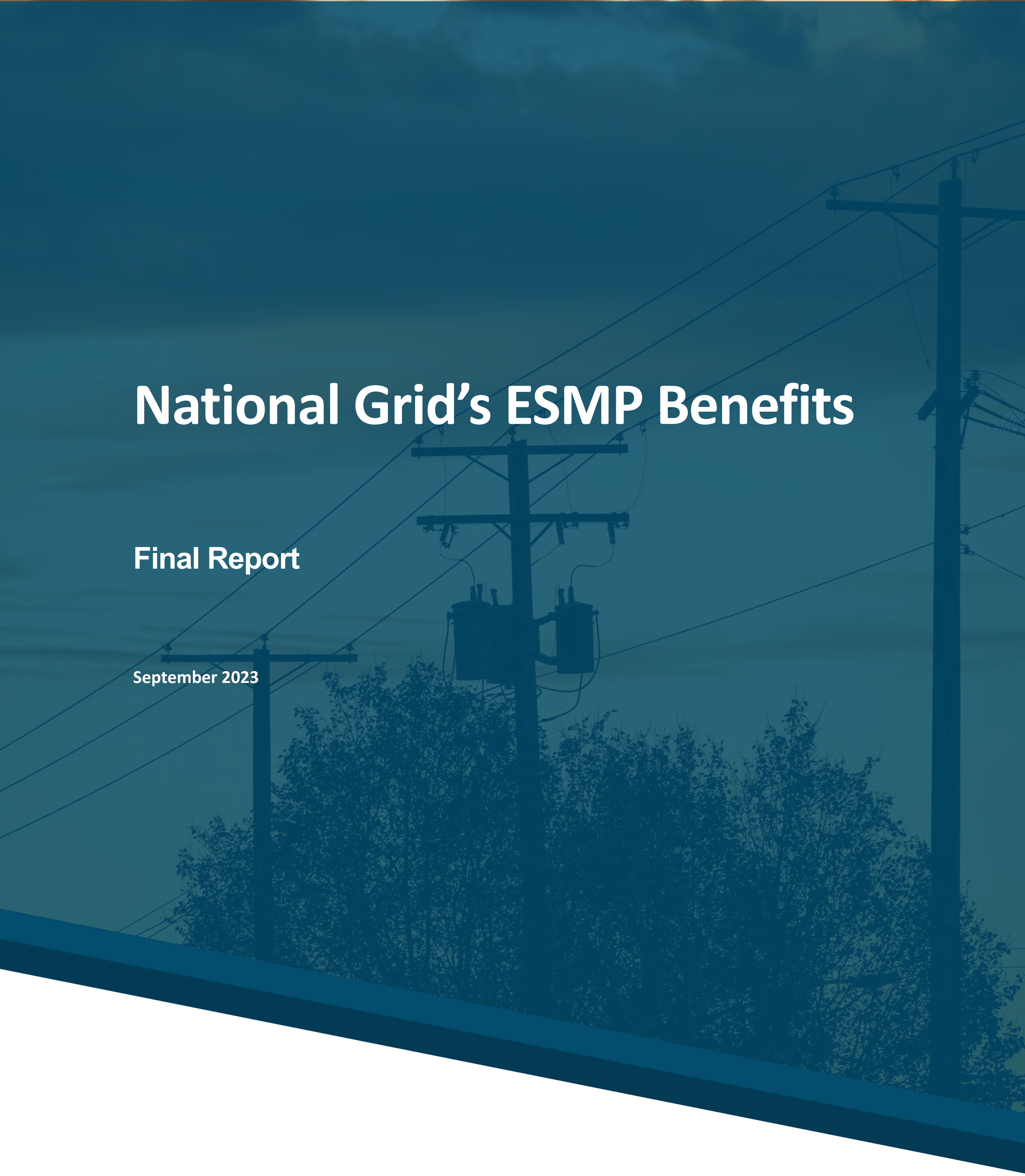
Exhibit 8: Report on the Societal Benefits of National Grid's ESMP proposal by E3



National Grid's ESMP Benefits

Final Report

September 2023

Energy+Environmental Economics

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Acronym Definitions

Acronym	Description
ADMS	Advanced Distribution Management System
AGIS	Advanced Grid Intelligence and Security
AI	Artificial Intelligence
AMI	Advanced Meter Infrastructure
BCA	Benefit Cost Analysis
BTM	Behind-the-Meter
C&I	Commercial and Industrial
CVR	Conservation Voltage Reduction
DER	Distributed Energy Resources
DERMS	Distributed Energy Resources Management Systems
DG	Distributed Generation
DOE	Department of Energy
DOE Guidebook	Strategy and Implementation Planning Guidebook
DPS	Department of Public Service
DR	Demand Response
DSP	Distributed System Platform
EDC	Electric Distribution Company
EE	Energy Efficiency
EJ	Environmental Justice
ESMP	Electric Sector Modernization Plan
EV	Electric Vehicle
FLISR	Fault Location, Isolation, and Service Restoration
GHG	Greenhouse Gas
GMP	Grid Modernization Plan
GRC	General Rate Case
HECO	Hawaiian Electric Company
IDP	Integrated Distribution Plan
ICE	Internal Combustion Engine
IRA	Inflation Reduction Act
IT/OT	Information Technology/Operational Technology
LDV	Light-duty Vehicles
DPU	Department of Public Utilities
MDV	Medium-duty Vehicles
ML	Machine Learning
NWA	Non-Wires Alternatives
NOx	Nitrogen Oxides
O&M	Operations and Maintenance

PM	Particulate Matter
PUC	Public Utilities Commission
SOx	Sulfur Oxides
STIP	Short Term Investment Plan
T&D	Transmission and Distribution
TVR	Time-Varying Rates
VPP	Virtual Power Plant
VVO	Volt-Var Optimization

Executive Summary

Background

In 2022, Governor Charlie Baker of Massachusetts signed An Act Driving Clean Energy and Offshore Wind ("Act") to move Massachusetts further toward achieving its ambitious climate goals of reaching net-zero emissions by 2050 and reducing its greenhouse gas (GHG) emissions by 85% from 1990 levels. The Act recognizes the transformational changes that will be needed across the economy and specifically to the electric grid to achieve 100% clean energy by 2050. The Act requires each electric distribution company (EDC) to develop an Electric Sector Modernization Plan (ESMP) to upgrade the distribution equipment to facilitate the transition to clean energy and electrification of end-uses. As part of the ESMP, each EDC must identify the benefits enabled by the ESMP investments.

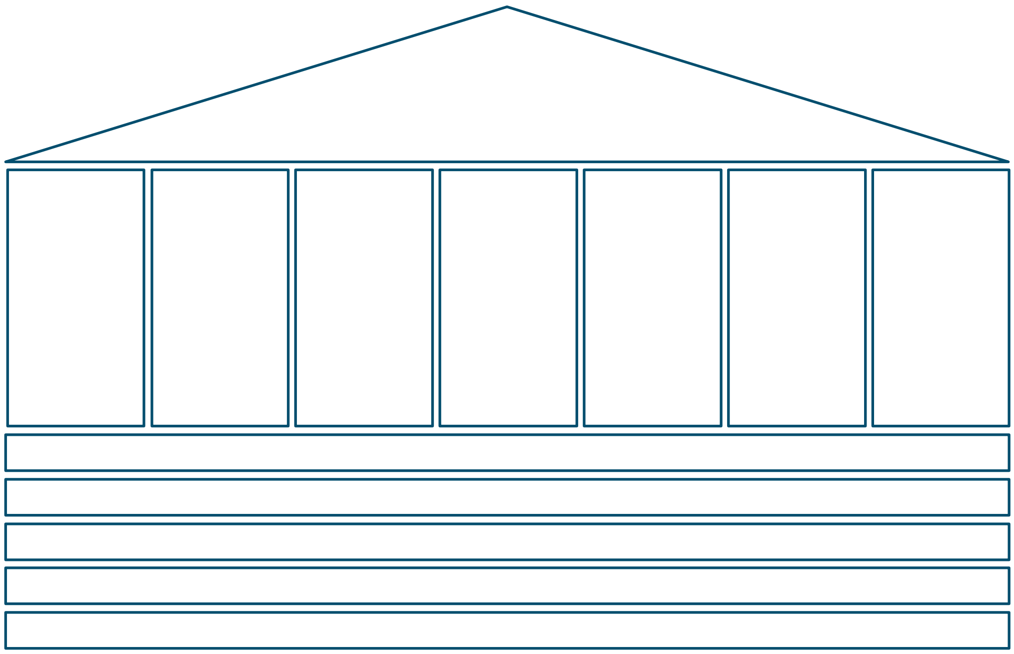
National Grid asked E3 to develop a stand-alone report focused on the benefits enabled by the ESMP investments to accompany their plan. This report identifies the key benefits enabled by the ESMP investments, explains how the investments facilitate the benefits, and summarizes National Grid's prior benefits-cost analyses (BCA). Importantly, this report does not review the correctness of National Grid's BCAs or conduct additional analysis to quantify benefits. Instead, it qualitatively describes the expected benefits from the ESMP and discusses National Grid's previously quantified benefits.

This report presents a framework explaining how National Grid's foundational and programmatic ESMP investments together enable key benefits. The report then provides an overview of National Grid's ESMP investment categories—Network Infrastructure, Technology Platforms, and Customer Programs—and details the types of investments within each category. The report goes on to explain the benefits that will be realized from the ESMP investments and how the investments enable each benefit. Following the discussion of benefits, the report summarizes National Grid's previous BCAs and examines how the benefits may evolve out to 2050.

Benefits Enabled by ESMP Investments

Transitioning to clean energy, electrifying end-uses, and integrating distributed energy resources (DERs) requires modernization of the electric grid. National Grid's ESMP includes foundational and programmatic investments to enable electric sector modernization as shown in Figure 1 and detailed in Section 6 and 7 of the ESMP. The investments span across categories—Network Infrastructure, Technology Platforms, and Customer Programs. The foundational investments shown at the bottom of the figure upgrade and expand the grid's core physical infrastructure and software upon which other investments and programs depend. The programmatic and application investments layer on top of this foundation, enabling additional functionality to directly provide benefits to National Grid's distribution system, customers, and society as a whole.

Figure 1. ESMP Investment to Benefit Framework



The key benefits enabled by the ESMP investments include reduction of GHG emissions to mitigate climate change, the reduction of air pollutants to improve public health, and the development of the economy and clean energy workforce. The ESMP investments will also improve grid reliability and resilience, contribute to grid safety, facilitate the integration of DERs, and enable greater transportation and building electrification. Finally, the ESMP investments will mitigate some land use impacts, reduce the curtailment of renewable energy, and, importantly, mitigate the impact to customer energy bills. For several investment categories, National Grid plans to prioritize programs in low-income and environmental justice (EJ) communities, directly generating benefits for those customers and communities. A mapping of the ESMP investment areas to the benefits is shown in Table 1.

Table 1. ESMP Investment to Benefits Framework

		Benefits									
		Reduced GHG Emissions & Climate Change Mitigation	Improved Health from Reducing Air Pollutants	Economic Development and Workforce Impacts	Grid Reliability and Resilience	Safety	Integration of DERs	Transportation & Building Electrification	Avoided Renewable Energy Curtailment	Mitigation of Land Use Impacts	Mitigation of Customer Bill Impacts
Network Infrastructure	Substation & Feeder Upgrades	Indirect	Indirect	Direct	Direct	Direct	Indirect	Direct	Direct	Indirect	Indirect
Technology Platforms	Network Management Comms	Indirect	Indirect	Direct	Direct	Direct	Direct	Indirect	Direct	Indirect	Direct
	Security	Indirect	Indirect	Indirect	Direct	Direct	Indirect	Indirect	Indirect	Indirect	Indirect
	Asset Planning, Management, & Work Execution	Indirect	Indirect	Indirect	Direct	Direct	Indirect	Indirect	Indirect	Indirect	Direct
	Data	Indirect	Indirect	Direct	Direct	Indirect	Direct	Indirect	Indirect	Indirect	Indirect
	Metering & Billing Systems	Direct	Direct	Direct		Direct	Direct	Direct			Direct
	Customer Portals			Direct			Direct				Direct
Customer Programs	Energy Efficiency, Demand Response, & Heating Electrification	Direct	Direct	Direct				Direct		Direct	Direct
	Clean Transportation	Direct	Direct	Direct			Direct	Direct	Direct		
	Non-Wires Alternatives	Direct	Direct	Direct	Direct		Direct		Direct		Direct
	Resilient Neighborhoods	Direct	Direct	Direct	Direct		Direct			Direct	
	Time-Varying Rates	Direct	Direct				Direct	Direct			Direct

Directly Enabled Benefit

Indirectly Enabled Benefit

Benefits Assessment

Benefits assessments are broadly employed by utilities to demonstrate that proposed investments provide benefits to customers. The Department of Energy (DOE) developed A Strategy and Implementation Planning Guidebook (DOE Guidebook) for grid modernization that has served as the foundation for grid modernization plans (GMP) and benefits assessments for several jurisdictions. The DOE Guidebook stresses the importance of aligning planned investments to their expected benefits and proposes a cost-effectiveness framework to evaluate investments.[1]

Several leading climate states, including Massachusetts, have established GMP filings and benefits assessments that are aligned with the best practices established in the DOE Guidebook.[2] Of these states, Massachusetts has established the most robust benefits assessments process.

National Grid has previously filed and received approval for BCAs for its GMP, advanced metering infrastructure (AMI), Energy Efficiency (EE), and electric vehicle (EV) programs to demonstrate that these investments result in significant net benefits to customers. Over the lifetime of the investments for these approved programs the net benefits range from $200M to $3,200M. Benefits are expected to continue out to 2050 as the investments enable more electrification and the integration of DERs and clean energy.

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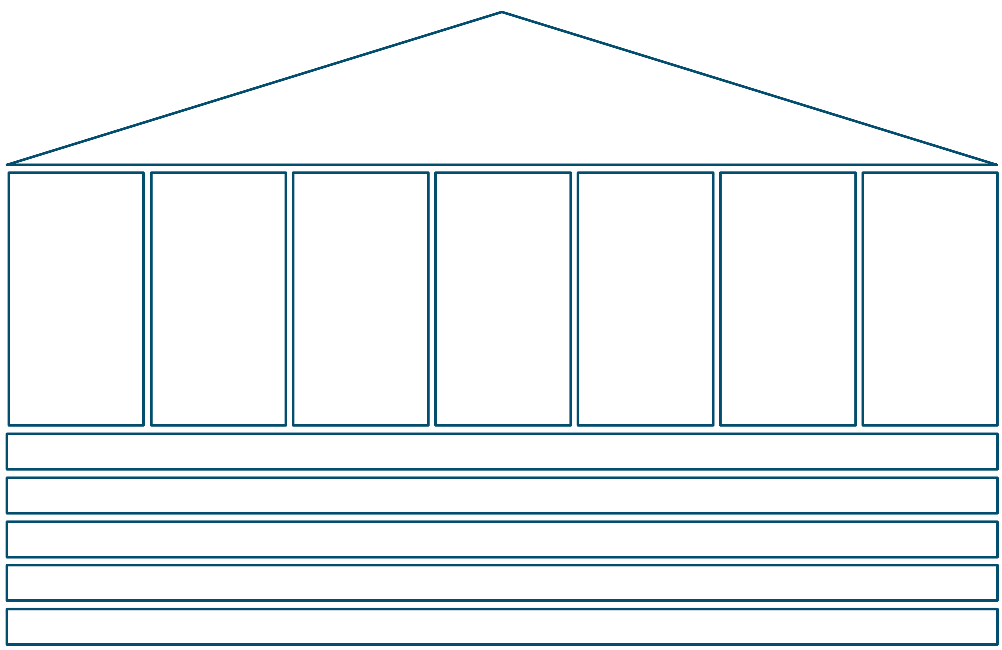
[1] Modern Distribution Grid DSPx, Strategy & Implementation Planning Guidebook Volume IV, Version 1 Final Draft, June 2020, (DOE Guidebook), https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume_IV_v1_0_draft.pdf

[2] Additional states' approaches to benefit assessments are described in Appendix 1.

Benefits Enabled by the ESMP

National Grid's ESMP investments result in benefits to the electric distribution system, customers, and society including climate and health benefits, job growth and economic development, grid reliability and resiliency, and mitigation of customer bill impacts. To achieve these benefits, National Grid is making foundational investments and programmatic investments as depicted in Figure 2 and described in Section 6 and 7 of the ESMP. Substation and feeder upgrades; network management and communications; security; asset planning, management, and work execution; and data investments upgrade and expand the grid's core physical infrastructure and software foundation enabling grid modernization. Additional Technology Platforms investments and Customer Program investments that are underway and newly proposed in the ESMP layer on top of this foundation as additional functionality to support clean energy resources, end-use electrification, grid applications, and demand-side programs that directly create benefits.

Figure 2. ESMP Investment to Benefits Framework



The benefits that result from the ESMP investments include climate change mitigation, improved health, grid reliability and resilience, development of the Commonwealth's economy and clean energy workforce, integration of DERs, avoided renewable energy curtailment, safety, mitigation of land use impacts, transportation and building electrification, and mitigation of customer bills. The foundational investments each support several benefits directly and enable additional benefits indirectly by supporting core grid functionality. The application and programmatic investments directly enable a subset of the benefits. Table 2 maps the investment categories to the benefits they enable, with directly enabled benefits in green and indirectly enabled benefits in gray.

Table 2. Benefits Enabled by ESMP Investments

		Benefits									
		Reduced GHG Emissions & Climate Change Mitigation	Improved Health from Reducing Air Pollutants	Economic Development and Workforce Impacts	Grid Reliability and Resilience	Safety	Integration of DERs	Transportation & Building Electrification	Avoided Renewable Energy Curtailment	Mitigation of Land Use Impacts	Mitigation of Customer Bill Impacts
Network Infrastructure	Substation & Feeder Upgrades	✓	✓	✔	✔	✔	✓	✔	✔	✓	✓
Technology Platforms	Network Management Comms	✓	✓	✔	✔	✔	✔	✓	✔	✓	✔
	Security	✓	✓	✓	✔	✔	✓	✓	✓	✓	✓
	Asset Planning, Management, & Work Execution	✓	✓	✓	✔	✔	✓	✓	✓	✓	✔
	Data	✓	✓	✔	✔	✓	✔	✓	✓	✓	✓
	Metering & Billing Systems	✔	✔	✔		✔	✔	✔			✔
	Customer Portals			✔			✔				✔
Customer Programs	Energy Efficiency, Demand Response, & Heating Electrification	✔	✔	✔				✔		✔	✔
	Clean Transportation	✔	✔	✔			✔	✔	✔		
	Non-Wires Alternatives	✔	✔	✔	✔		✔		✔		✔
	Resilient Neighborhoods	✔	✔	✔	✔		✔			✔	
	Time-Varying Rates	✔	✔				✔	✔			✔

✔ Directly Enabled Benefit ✓ Indirectly Enabled Benefit

ESMP Investment Categories

Each of the following investment categories describes the specific infrastructure, application, and program investments that will be made to enable the ESMP benefits. These categories include efforts that are underway and already approved as well as investments that are proposed to be funded via the ESMP or via separate proposals. For further details on specific categories of investment, refer to Section 6 and 7 of the ESMP.

Network Infrastructure Investments

Substation & Feeder Upgrades

Networks investments include substation, feeder, and transformer upgrades. These are foundational investments that add substation and feeder headroom to support increased electrification, load relief, accommodate two-way power flow, and integration of DERs.

Technology Platforms Investments

Network Management & Communications

Network Management & Communications investments enable effective network insight through real-time network visibility and control to support the asset operations and optimization. It enables the exchange of information and control with residential and small commercial DER technologies and provides a means of connecting and managing data communications in a wide variety of fixed and mobile assets within the electric grid. These are foundational investments that oversee and optimize real-time grid conditions and load balancing, enable and optimize integration of DERs, and allow more loads to be added to the grid from electrification.

Current/Previously Approved	Proposed (to be funded via ESMP)
• ADMS • DERMS Phase I • FLISR • VVO / CVR • Grid Modernization Communications	• Active power restoration services (ADMS extension) • DERMS Phase II • Expanded FLISR • Expanded VVO/CVR • Expanded Grid Modernization Communications • Enterprise Network Communications • Future of Network Management Demonstration Projects

Metering & Billing Systems

Metering & Billing Systems technologies, such as AMI and enhanced billing, measure customer energy usage.

AMI gives customers access to new products and technology, while incentivizing them to actively participate in energy markets, manage energy consumption, and control costs. Granular, time-series data from smart meters and other intelligent devices at customers' premises enable advanced analytics, innovative rate designs, and customer engagement strategies that benefit both the customers and the grid. AMI deployment also allows for customers and authorized third-party service providers to access detailed energy use data.

Enhanced billing for time-varying rates (TVR) provides more dynamic incentives to customers for altering their energy usage in ways that provide value to the grid without impacting the customer experience, such as local demand response (DR) events, managed EV charging, and flexible demand.

Current/Previously Approved	Proposed (to be funded via ESMP)
• AMI	• TVR Billing System Engine

Customer Portals

Customer choice, flexibility, and ease of interconnection (both load and supply) will hinge on broader data sharing capabilities and management of customer programs. Customer portals investments facilitate management of customer programs related to EE, EVs, and new customer interconnections. Within the ESMP, specific proposals are made for a Clean Energy Platform 2.0 and DER Customer Experience Enhancements.

Data

Data investments manage data sharing with customers, developers, and other stakeholders. These are foundational investments for facilitating data exchange between systems and devices and providing customers with real-time access to their data. Data systems, interoperability, and sharing are key to enabling grid modernization.

Current/Previously Approved	Proposed (to be funded via ESMP)
• Data management platform • AMI	• Intelligent data capture • Grid asset data enhancements

Asset Planning, Management, & Work Execution

Asset Planning, Management, & Work Execution investments are the foundation to manage assets and the workforce needed to maintain the grid infrastructure. Investments in machine learning (ML) and artificial intelligence (AI) improve efficiency and optimize asset management. More accurate predictions of asset health and lifespan minimize downtime, reduce emergency repairs, and improve network reliability. Leveraging AI to analyze satellite, drone, and LIDAR data will locate vegetation that pose risks to network reliability. Better data optimizes the deployment of field crews and ensures tasks are completed efficiently. New digital products to support ESMP objectives are proposed in this plan.

Security

Security investments protect digital technology systems and physical assets from impacts to their confidentiality, integrity, and availability to operate on a connected network. Security investments are foundational to the increased use of digital solutions and will reduce exposure to malware and unintentional errors that could result in data breaches or system compromise.

Current/Previously Approved	Proposed (to be funded via ESMP)
• Foundational security investments	• Enhanced security investments

Customer Program Investments

Energy Efficiency, Demand Response, and Heating Electrification

Energy Efficiency, Demand Response, and Heating Electrification programs are available to residential and commercial and industrial (C&I) customers to help with the adoption of heat pumps and other energy efficient technologies, like improved insulation, efficient appliances, and smart thermostats. The investments also include C&I and residential DR programs that are designed to help manage system-wide peaks, equity initiatives, workforce development efforts, contractor engagement, and community partnership programs. The ESMP envisions that these underway programs would scale and evolve through separate filings in the next Three-Year Energy Efficiency Plan for 2025–2027.

Current/Previously Approved	Proposed (to be funded through separate filings)
• EE incentives for Residential and C&I customers, including specific efforts for income-eligible and EJ populations • Incentives to control devices (e.g., thermostats, batteries) • C&I incentives to reduce load or increase exports during peak load events • Residential and C&I incentives for electric heat pumps	• Scaling of current/previously approved programs

Clean Transportation Programs

Clean Transportation program investments incentivize EV adoption and accommodate growing transportation electrification loads.

- **Flexible Connections for EVs**: This newly proposed option would allow EV fleet operators to connect to the grid for charging in advance of system upgrades by allowing National Grid to actively manage charging.
- **Scale and Evolve Clean Transportation Programs:** Underway clean transportation and EV charger programs support the growth of EVs, providing incentives to support the deployment of EV charging stations in the residential, public and workplace, and fleet customer segments. Under ESMP proposals, current Phase III EV programs will scale and evolve further.

Current/Previously Approved	Proposed (to be funded via ESMP)
• "Make-ready" incentives for EV charging installations • Off-peak charging rebate program	• Scaling of "make-ready" incentives • Flexible Connections for EVs

Non-Wires Alternatives

National Grid has identified three categories of Non-Wires Alternatives (NWA) solutions that may be deployed to help reduce the likelihood and severity of expected overloads before needed network infrastructure projects can feasibly be constructed in areas that have the most significant overloading risk. The NWA solutions being explored through the ESMP are:

- **Targeted Energy Efficiency and Demand Response as Non-Wires Alternatives:** This solution would offer additional EE and DR incentives to customers to reduce peak load based on targeted distribution network constraints.
- **Residential Virtual Power Plant (VPP) Pilot**: This pilot solution would aggregate BTM residential solar, connected batteries, and smart thermostats to deliver grid services based on targeted distribution network constraints.
- **Leverage Flexibility Market Platform for Non-Wires Alternatives:** This solution would run auctions for flexibility service products based on targeted distribution network needs.

Resilient Neighborhoods Program

Under the Resilient Neighborhoods Program proposed in the ESMP, National Grid would construct, own, and operate solar generation facilities paired, where feasible, with energy storage facilities. These projects are to be designed to improve community climate adaptation and resiliency for municipalities within National Grid's territory. The program would develop projects to support communities in need, with a strong preference for bringing benefits to EJ communities. National Grid intends to file plans for this program in a separate proceeding once detailed projects, costs, and benefits are determined.

Time-Varying Rates

New electricity rate designs, enabled by National Grid's investment in AMI and the TVR Billing System Engine as part of the Technology Platform investments, can provide customers with incentives and choices that support smart use of the grid, incentivize electrification, and reduce the overall costs of the energy transition. National Grid intends to formally propose AMI-enabled TVRs as part of a separate proceeding.

Key Benefits

In the following sections, each of the key benefits are described. Each section contains a table identifying the investment categories that directly enable the benefit and describe how the investment will enable the benefit.

Reduced GHG Emissions and Climate Change Mitigation

ESMP investments that result in the reduction of fossil fuels in electricity generation and end-uses lowers GHG emissions, mitigating the impacts of climate change. GHG emission reductions are a result of a cleaner electricity supply from increased penetration of renewable energy that is enabled by capacity expansion and grid modernization. Additionally, higher integration of zero- or low-carbon DERs will result in less reliance on fossil fuel generation that emits carbon dioxide and methane which are significant contributors to climate change.

The 2022 Massachusetts Climate Change Assessment identified potential climate impacts and risks for the state.[3] Key climate hazards for Massachusetts include warmer temperatures and more frequent heat waves that are connected to impacts on public health, droughts, lower agriculture yields, and a need for infrastructure repairs.[4] More frequent seasonal droughts, more intense days of high rainfall, stronger and more frequent coastal storms, and gradual sea level rise are also projected changes. These extreme weather events impact water supply and agriculture, stress vulnerable ecosystems, damage infrastructure, and disrupt services like transportation, electricity, and sanitation.[5]

Damages caused by climate change reverberate through local communities, disrupting the economy and burdening residents with the cost of the damages. Extreme weather events shut down businesses and reduce work time, especially impacting minority workers who make up a disproportionate share of the labor force working outside during extreme heat.[6] Floods and sea level rise limit the availability of

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[3] Massachusetts Climate Change Assessment, 2022, https://www.mass.gov/info-details/massachusetts-climate-change-assessment

[4] Climate Change Impacts by Sector, U.S. Environmental Protection Agency, https://www.epa.gov/climateimpacts/climate-change-impacts-sector

[5] Ibid.

[6] Massachusetts Climate Change Assessment, 2022, https://www.mass.gov/info-details/massachusetts-climate-change-assessment

affordably priced housing due to direct property damage and scarcity caused by increased demand, further exacerbating known inequities in accessing affordable housing.[7] Warming ocean temperatures can impact marine fisheries and aquaculture productivity, harming key industries in the Commonwealth.[8] By reducing GHG emissions, the ESMP investments will reduce the likelihood of these climate impacts in Massachusetts and beyond.

Table 3. Investments Leading to Reduced GHG Emissions and Climate Change Mitigation

Investment Category	How Investment Enables Benefit
Metering & Billing Systems	AMI technology facilitates DER interconnection, TVR for load shifting, and reduced truck rolls for metering services, all of which can reduce GHG emissions.
Energy Efficiency, Demand Response, and Heating Electrification	EE investments reduce electricity generation from fossil fuels that produce GHG emissions. Heat pumps electrify building heating and cooling and run more efficiently than combustion heating systems, which reduce building GHG emissions.
Clean Transportation Programs	Make-ready programs and flexible connections provide aid in the adoption of EVs, which reduce tailpipe GHG emissions from the alternative ICE vehicles.
Non-Wires Alternatives	VPPs aggregate and dispatch DERs to optimize real-time grid conditions, load balancing, and use of DERs, which reduce GHG emissions. Targeted EE and DERs reduce consumption of energy at peak times, reducing GHG emissions and avoiding distribution constraints.
Resilient Neighborhoods	Distributed solar can reduce reliance on fossil fuel generation, reducing GHG emissions.
Time-Varying Rates	TVR enables customers to shift load to off-peak hours, accessing cleaner generation. This shift reduces GHG emissions and leads to improved climate outcomes.

Improved Health from Reducing Air Pollutants

Reducing fossil fuel use improves outdoor and indoor air quality, resulting in better public health outcomes. Specifically, investing in clean energy resources instead of fossil fuel resources and EVs instead of internal combustion engine (ICE) vehicles reduces outdoor air pollution across Massachusetts, while building electrification can improve indoor air quality.

Criteria air pollutants, such SO_x, NO_x, and $PM_{2.5}$, have well-documented impacts on respiratory and cardiac disease.[9] Reducing air pollutants decreases the risk of asthma, lung cancer, and heart attacks, reducing

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[7] Ibid.
[8] Ibid.
[9] Criteria Air Pollutants, U.S. Environmental Protection Agency, https://www.epa.gov/criteria-air-pollutants

the likelihood of premature death and improving overall public health.[10] While improving ambient outdoor air quality has positive health impacts for all, it can especially benefit low-income, EJ, and other vulnerable populations who may face either higher concentrations of ambient air pollutants or greater sensitivity to their impacts.[11] Reducing the air pollutants that result from fossil fuel combustion improves the public health outcomes for these populations.

Reducing GHG emissions decreases the public's risk of exposure to health-related impacts caused by climate change. Climate change increases temperatures and creates conditions that form ozone and particulate matter, contributing to the harmful health impacts of air pollution.[12] Climate change also increases the likelihood of extreme weather events and heat waves that can exacerbate pre-existing health conditions, leading to injuries, illness, and premature deaths.[13] Rising temperatures can spread diseases caused by insects and viruses and increase the likelihood of food and water-borne disease.[14] Climate change may limit crop production or cause more pests, leading to wider food insecurity. Heat and natural disasters can also lead to trauma and higher levels of anxiety and depression, potentially worsening the mental health crisis.[15] ESMP investments that enable GHG emission reductions mitigate climate change, reducing the possibility of these public health outcomes.

In addition to the outdoor air quality benefits, building electrification improves indoor air quality. Heat pumps, for example, provide several indoor air benefits that increase both health and comfort.[16] Heating exclusively with heat pumps eliminates the risk of carbon monoxide poisoning. Carbon monoxide is a byproduct of combustion and therefore is a risk when burning oil, gas, or wood to heat a home. Carbon monoxide can cause illness, hospitalization, and in severe cases, death.[17] In cases where homes are heated exclusively with wood, not only is carbon monoxide a health hazard, but particulates, nitrogen oxides, and volatile organic compounds decrease air quality as well.[18] Another indoor air quality benefit of heat pumps is air filtration and humidity control, which can reduce pathogens and mold growth indoors.

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[10] Ibid.

[11] Research on Health Effects from Air Pollution, U.S. Environmental Protection Agency, https://www.epa.gov/air-research/research-health-effects-air-pollution#health-effects-vulnerable-pops

[12] Climate Change and Air Pollution, American Lung Association, https://www.lung.org/clean-air/climate-change/climate-change-air-pollution

[13] Climate Change Impacts on Health, U.S. Environmental Protection Agency, https://www.epa.gov/climateimpacts/climate-change-impacts-health

[14] Ibid.

[15] Ibid.

[16] Massachusetts Clean Energy Center, https://goclean.masscec.com/heatpump

[17] Carbon Monoxide, American Lung Association, https://www.lung.org/clean-air/at-home/indoor-air-pollutants/carbon-monoxide

[18] Residential Wood Burning, American Lung Association, https://www.lung.org/clean-air/at-home/indoor-air-pollutants/residential-wood-burning

Table 4. Investments Leading to Improved Health

Investment Category	How Investment Enables Benefit
Metering & Billing Systems	AMI technology facilitates DER interconnection and reduces truck rolls for metering services, reducing air pollutants that negatively impact health.
Energy Efficiency, Demand Response, and Heating Electrification	Heat pumps electrify building heating and cooling and run more efficiently than combustion heating systems, reducing indoor air pollution, and resulting in health benefits.
Clean Transportation	Make-ready programs and flexible connections aid in the adoption of EVs, which reduce tailpipe GHG emissions from ICE vehicles, leading to health benefits locally and across the Commonwealth.
Non-Wires Alternatives	VPPs aggregate dispatch of DERs to optimize real-time grid conditions, load balancing, and use of DERs, which reduce air pollutants.
Resilient Neighborhoods Program	DG and storage can help avoid distribution constraints and the need for fossil fuel peaker plants, reducing air pollution and leading to health benefits.
Time-Varying Rates	TVR enables customers to shift load to off-peak hours, accessing cleaner generation. This shift reduces air pollutants and leads to improved health outcomes.

Economic Development and Workforce Impacts

National Grid's ESMP investments will lead to economic and jobs growth in the Commonwealth as National Grid invests in its own infrastructure and programs and enables growth in other sectors. National Grid's spending will directly create jobs within the utility and in construction, as well as indirectly create jobs in supply or service industries that are supported by ESMP investments. The personnel supported by these jobs will then spend a portion of their wages in the local and broader economy, inducing further job growth and economic development.

Some spending and job creation will be more local in nature, while other spending will have broader geographic impacts. Network infrastructure upgrades will result in infrastructure spending in local construction and some materials sourcing. Customer program investments will enable growth of local industries, such as HVAC and rooftop solar installers. More broadly, infrastructure and program spending will engage upstream suppliers and downstream service industries across Massachusetts and outside the Commonwealth. Investments will also enable further decarbonization investments and subsequent job creation in other sectors including the buildings, transportation, solar, wind, and storage industries.

In addition to jobs, ESMP investments will enable customers and businesses to take advantage of incentives made available by the Inflation Reduction Act (IRA). The IRA creates prevailing wage and apprenticeship requirements to be eligible for many clean energy project incentives, facilitating well-paying local jobs and workforce development programs. The ESMP investments enable greater adoption of efficient and electric appliances by customers that can apply for IRA rebates and tax credits, spurring more spending in downstream service industries.

Table 5. Investments Leading to Economic Development and Workforce Impacts

Investment Category	How Investment Enables Benefit
Substation & Feeder Upgrades	Investments will create economic activity and jobs in sectors directly involved in building and maintaining electrical infrastructure, including construction, engineering, and O&M. Investments may also create additional employment and economic activity in sectors that provide materials and services to electric infrastructure upgrades.
Network Management & Communications	Investments will likely create jobs installing software, field devices and support ongoing device and software maintenance roles. Investments will also likely make data available to software/modeling businesses, indirectly creating additional jobs (e.g., DERMS third-party aggregators).
Data	Investments will likely create roles for processing and managing data, contractor roles for installing communication and IT/OT systems and support other roles for managing IT/OT systems.
Metering & Billing Systems	Investments will likely create meter, telecommunication, and software installation jobs and ongoing maintenance. The investments will also likely create data collection and analysis roles, including by third-party energy aggregator companies.
Customer Portals	Investments will likely create roles for managing platforms and indirectly create jobs for third-party DER aggregators.
Energy Efficiency, Demand Response, and Heating Electrification	Ongoing investments in EE, DR, and electrification will likely support jobs in energy service companies that cover a range of specialties, including home energy assessments and monitoring, installation of equipment such as HVAC and weatherization, behavior modification EE programs, and education and outreach.
Clean Transportation Programs	Investments will likely support EV charging-related jobs, such as at companies specializing in make-ready infrastructure and charging infrastructure design and installation.
Non-Wires Alternatives	NWA procurement will likely create economic activity among service providers for solutions including VPP, targeted EE and DR, and Flexibility Markets.
Resilient Neighborhoods Program	Anticipated development of this program will result in further economic activity in development of solar and storage in selected neighborhoods.

Grid Reliability and Resilience

Reliability is the electric grid's ability to perform as expected during normal operating conditions, withstand expected unscheduled outages of system components, and in the event of expected unscheduled contingencies, recover quickly while limiting the scope of the instability and cascading outages. This description largely derives from North American Electric Reliability Corporation's definition of Adequate Levels of Reliability.[19] Resilience, on the other hand, is meant to convey many of the same grid attributes—withstand, react to, and recover quickly from disruptions but in the case of extreme weather-related events such as hurricanes, snowstorms, or extreme heat.

Society's increased reliance on electricity to support electrified transportation, building heat, and high-tech industry demands a high level of grid reliability and resiliency. At the same time, the flow of electricity to support customer loads is becoming more complex. Intermittent resources like solar and wind are causing changes to supply patterns, while new customer technologies, programs, and higher electrification loads are causing changes to demand patterns. Maintaining grid reliability is important to support the system without increasing outages or other power flow issues. Resiliency is required to face extreme events—such as coastal flooding, high-temperatures, and extreme winds—as well as the ability to restore electric service as quickly as possible after an outage.

[19] Definition of Adequate Level of Reliability, North American Electric Reliability Corporation, https://www.nerc.com/pa/Stand/Resources/Documents/Adequate_Level_of_Reliability_Definition_(Informational_Filing).pdf

Table 6. Investments Leading to Reliability and Resiliency

Investment Category	How Investment Enables Benefit
Substation & Feeder Upgrades	Infrastructure upgrades built to stricter codes and standards result in less frequent failures that increase grid reliability. Network investments result in fewer long-duration critical outages during extreme weather events, increasing system resilience.
Network Management & Communications	Telecommunications provides monitoring and control of electric distribution equipment to optimize grid conditions and manage outages. FLISR reduces outage frequency and length. DERMS allows control of residential and customer DER technologies which enables stable, secure, and repeatable performance, all leading to a more reliable and resilient grid.
Security	Investments protect software systems and physical assets from security threats and malware, enabling stable and secure operations and reducing the likelihood of system compromise to ensure a more reliable and resilient grid.
Asset Planning, Management, & Work Execution	Investments that manage grid assets to predict asset health, minimize downtime, and monitor risks improve network reliability. More efficient identification of necessary repairs and faster deployment of field crews improves system resilience.
Data	Investments ensure interoperability across systems and devices enabling better management of DERs and reliable and resilient operations.
Non-Wires Alternatives	NWA solutions, such as VPP and Flexibility Markets, provide a mechanism to manage the network safely and reliably while continuing to integrate EVs and electrification of heating.
Resilient Neighborhoods	DG and energy storage can provide electricity during outages, including those which occur during days with peak demands and during extreme weather events, leading to a more reliable and resilient grid.

Safety

As the grid is changing with the integration of DERs, two-way power flow, and higher energy demands, maintaining safe operations for customers and workers is of paramount importance. Public safety concerns include protection from dangerous events like fires and electrocution from defective equipment. Reliability-related safety concerns are also important, like dangerous events caused by outages for at risk customers or other accidents.

National Grid's ESMP investments improve asset monitoring and operational capabilities. These projects enable utilities to use near real-time asset data to manage maintenance and replacement of grid infrastructure. The utility can use this capability to replace equipment on a health-basis rather than on a time-in-service basis, which may minimize critical equipment failure, reducing the overall need for workers to replace faulty (and potentially) dangerous equipment. Additionally, National Grid's Network

Infrastructure investments are being built to more stringent construction codes and standards. This further ensures fewer critical failures and enhances worker safety.

Investments such as fault location, isolation, and service restoration (FLISR) also have safety synergies with anti-islanding capabilities in Massachusetts's interconnection requirements. If a fault occurs on the distribution system, FLISR isolates the fault while automatically and safely restoring power to as many customers as possible. Interconnection requirements enhance these safety features by preventing "unintentional islands" which are known to result in safety hazards for personnel and equipment-damaging out-of-phase conditions and transient voltages.[20]

Table 7. Investments Leading to Safety

Investment Category	How Investment Enables Benefit
Substation & Feeder Upgrades	Investments provide essential reliability and safety functions, such as voltage management and preventing power surges.
Network Management Communications	Investments supporting network development result in fewer outages and fewer trips to resolve outages/issues, thereby minimizing safety impacts on customers or personnel.
Security	Investments in security software protect from malware and provide a stable platform for distributed services.
Asset Planning, Management, & Work Execution	Investments use ML and AI to manage assets, lowering the risk of emergency repairs and reducing the need for field crews to work in dangerous conditions.
Metering & Billing Systems	Remote sensing and operational capabilities of AMI result in fewer trips to connect, disconnect and resolve outages or other issues, thereby minimizing safety impacts on customers or personnel.

Integration of DERs

DERs exist on a small scale on the customer's side of the meter. Examples of DER technologies include renewable DG, EVs, electric heat pumps, or advanced "smart" technologies used to actively manage energy use in customers' homes and places of business. DER penetration is projected to rapidly accelerate over the next few years. If managed correctly, there is tremendous opportunity to utilize integrated DERs to maintain grid reliability, level out peak demands which minimizes the needs for T&D upgrades and reduce dependence on fossil fuel energy generation which results in environmental and health benefits. In addition to these grid benefits, DERs can also be used by the customer to reduce electric bills. Integration of DERs limits the need for larger scale fossil fuel generation and corresponding air pollutants.

[20] California's Grid Modernization Report, California Public Utilities Commission, 2020, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2020/californias-grid-modernization-report-2020.pdf

Table 8. Investments Leading to Integration of DERs

Investment Category	How Investment Enables Benefit
Network Management Communications	Investments that oversee and optimize real-time grid conditions, load balancing, and management and optimization of DERs will enable greater integration of DERs.
Data	Investments that improve data management, interoperability of systems, and customer access to data are essential to integration of DERs.
Metering & Billing Systems	Investments enable data collection and analysis within the utility and by third-party energy aggregator companies, allowing the utility to leverage DER resources to support grid needs.
Customer Portals	Customer portals help customers and third-party aggregators manage DERs, incentivizing DER adoption and enabling better integration.
Clean Transportation Programs	Programs that support the deployment of EV charging stations and provide flexible connections for EVs will enable greater and more timely customer adoption of EVs. This in turn amplifies the ability of EV vehicle-to-grid functionality to serve grid needs.
Non-Wires Alternatives	NWAs leveraging BTM residential solar, connected batteries, and smart thermostats to deliver grid services provide a greater use case for these resources.
Resilient Neighborhoods Program	The program will integrate new DER projects in the form of solar and storage facilities, specifically in EJ communities.
Time-Varying Rates	Investments encourage the use of energy when there is more renewable energy on the grid, leading to increased utilization of the energy and services that DERs provide.

Transportation and Building Electrification

A central climate mitigation strategy is the electrification of end uses, given that electricity will increasingly be generated with clean resources, such as wind and solar. In residential and commercial buildings, space heating and cooling and water heating are significant energy users and thus are prime candidates for electrification. The most common technologies for heating and cooling electrification are electric heat pumps, which offer much greater efficiency than their fossil fuel counterparts and are quickly evolving to meet and exceed the heating demands of cold climates. Investments provide rebates for low-income customers to adopt heat pumps and other EE technologies, allowing them to participate in the savings from lower energy consumption and ensuring equitable access to building heating and cooling.

The transportation sector, which is a significant contributor to Massachusetts' GHG emissions,[21] offers another high-impact opportunity to reduce emissions through electrification. Transportation electrification is achieved by replacing internal combustion vehicles with EVs, including buses, trains, personal light duty vehicles (LDV), and various classes of heavy-duty vehicles, such as semi-trucks and farm equipment. EVs do not produce emissions as they are being driven, minimizing the amount of air pollution in cities and along roadways.

Table 9. Investments Leading to Electrification

Investment Category	How Investment Enables Benefit
Substation & Feeder Upgrades	Investments in network capacity are scoped to respond to projected demand for electrification of transportation and heating, directly enabling these outcomes.
Metering & Billing Systems	AMI and technology platform investments provide real-time, granular data on energy consumption patterns, allowing utilities to better manage the increased demand that comes with electrification. These investments also enable TVR and the implementation of DR or flexible demand programs which shift consumption to hours that can accommodate more load, enabling greater levels of electrification.
Energy Efficiency, Demand Response, and Heating Electrification	Investments enable heat pump adoption for space and water heating, facilitating the electrification of building heating and cooling.
Clean Transportation Programs	Investments provide rebates for the integration of EV charging stations in residential, workplace, and fleet charging programs, which provide necessary resources for widespread transportation electrification. Flexible connections enable faster deployment of EVs and transition away from ICE vehicles.
Time-Varying Rates	TVR allows customers to shift EV charging and use of electric water heaters to hours that can accommodate more load, enabling greater levels of electrification.

Avoided Renewable Energy Curtailment

As more renewable energy sources come online, there are higher chances of curtailment of those sources to balance system loads. This occurs when there is an oversupply of renewables like solar or wind during a time when demand is lower than the supply. Reduced curtailments are beneficial to society for a cleaner electricity supply, for potentially lower supply costs, and to the renewable energy plant owner to receive full compensation for the power output.

[21] Massachusetts Clean Energy and Climate Plan for 2025 and 2030, 2022, https://www.mass.gov/doc/clean-energy-and-climate-plan-for-2025-and-2030/download, p. 7

Table 10. Investments Leading to Avoided Renewable Energy Curtailment

Investment Category	How Investment Enables Benefit
Substation & Feeder Upgrades	Investments ensure efficient power flow in the distribution network as more DERs are integrated, minimizing renewable energy curtailment.
Network Management Communications	Investments that oversee and optimize real-time grid conditions, outage management, load balancing, and optimization of DERs maximize the usage of renewable energy.
Clean Transportation Programs	Investments in off-peak charging rebates incentivize charging during off-peak times, providing peak shaving benefits for the entire system and minimizing the curtailment of renewable resources.
Non-Wires Alternatives	NWAs such as battery storage may help reduce renewable curtailment by storing excess renewable energy, which can be used when demand exceeds renewable generation.

Mitigation of Land Use Impacts

Traditionally, large-scale utility generation can have a large impact on land use. While utility-scale renewable investments are needed, investments for improving DER adoption, EE, and DR programs can mitigate land use impacts by reducing overall energy consumption. Most DERs have a small physical footprint since they can be installed on existing structures, reducing the need for additional land use. DERs, EE, and DR programs can lower system wide energy demand, reducing the need for building large scale generation and distribution which have a larger footprint. Similarly, the distributed nature of DERs allows energy to be harnessed closer to the point of consumption, reducing the need for large, centralized power plants and the associated land requirements.

Table 11. Investments Leading to Mitigation of Land Use Impacts

Investment Category	How Investment Enables Benefit
Energy Efficiency, Demand Response, and Heating Electrification	Investments in EE programs reduce energy demand, which minimizes the need for additional generation and infrastructure.
Resilient Neighborhoods	Investments facilitating on-site DG and storage provide energy while reducing the need for large-scale generation and distribution and the associated land requirements.

Mitigation of Customer Bill Impacts

Achieving Massachusetts's clean energy and climate goals requires significant electric sector improvements to accommodate the increased load from electrification and to maintain the safety, reliability, and resiliency of the grid. These improvements are often expensive, putting upward pressure on electricity rates and impacting customer affordability.

To mitigate these impacts, National Grid is making investments, such as EE, volt-var optimization (VVO), and DERs, that reduce the need for more expensive investments, resulting in avoided costs. More advanced grid management tools, improved grid awareness, less frequent outages, and advanced equipment lead to avoided operational costs. Load shifting achieved from energy storage, rate design, and other investments leads to lowered system peak and avoided energy and operational costs. Many of these investments reduce the need for further build out of the T&D system, contributing to T&D avoided costs. These avoided costs are passed along to the customers through lower rates.

Impacts to the customer bills are further minimized through Customer Program investments by including rebates for low-and moderate-income customers to allow them to participate in many of the grid improvements and to install more efficient home appliances, weatherize homes and businesses, and install efficient electric heat pumps.

Table 12. Investments Leading to Mitigation of Customer Bill Impacts

Investment Category	How Investment Enables Benefit
Network Management & Communications	Foundational investments that support the optimization of grid planning and operations reduce the need for infrastructure upgrades, avoiding costs for the utility which will be passed down to customers.
Asset Planning, Management, & Work Execution	Foundational investments will better manage assets to predict asset health and reduce emergency repairs, avoiding capital costs. Investments will more efficiently deploy field crews and monitor risks to the grid, avoiding O&M costs. These cost savings will be passed down to customers.
Metering & Billing Systems	Advanced metering enables the implementation of Demand Response and Flexible Demand programs which decrease peak demand, avoiding capacity and infrastructure upgrade costs that will be passed down to customers. AMI also reduces the need for field sensors and truck rolls for data collection, lowering operational expenses, which are passed to the customer through lower rates. TVR Billing System Engine investments will provide technology solutions to operationalize TVR. Investments allow customers to see more granular consumption data and adjust their consumption accordingly.
Customer Portals	Investments enable customers to adopt BTM technologies that increase efficiency and enable load shifting, which can lower bills.
Energy Efficiency, Demand Response, and Heating Electrification	Weatherization and electric heat pump rebates allow for more customers to install equipment that lowers their energy usage and resulting bills.
Non-Wires Alternatives	NWAs allow for deferral or avoidance of a wires solution, reducing or delaying system upgrades and associated costs to customers.
Time-Varying Rates	TVR allows customers to shift use of electric appliances and EVs to hours with lower rates to reduce their energy bills.

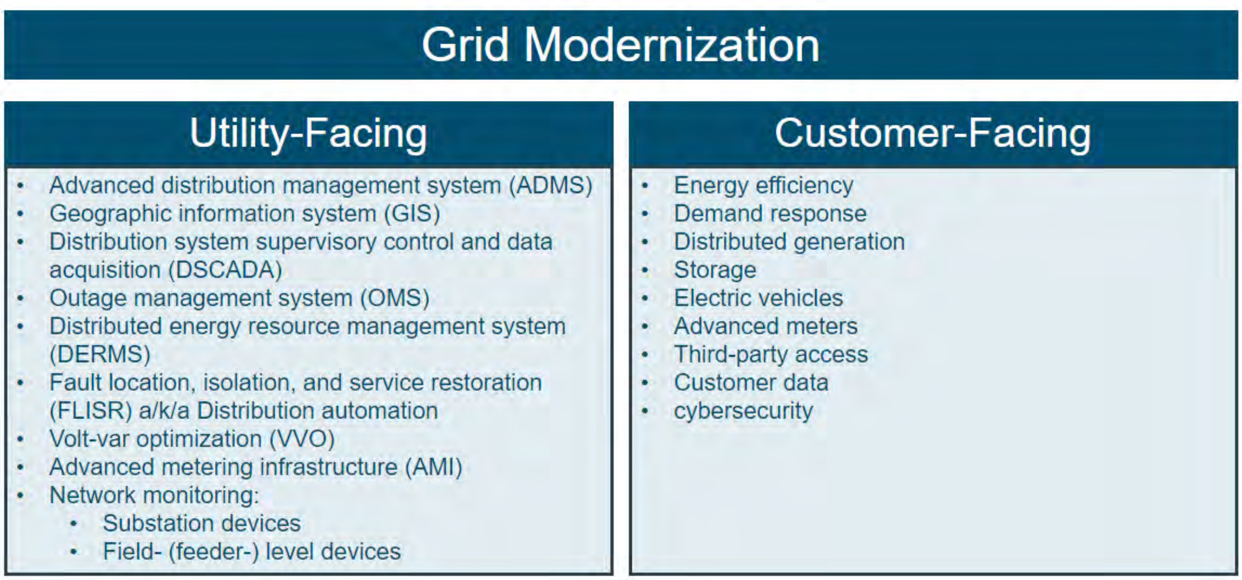
Benefits Assessment

Benefits Assessment Framework

Benefit assessments are widely employed by utilities to demonstrate that proposed investments provide benefits to customers. The assessments are routinely included in rate cases or separate investment filings and are considered by regulators to either pre-authorize investments or to provide recovery for investments that have already been incurred.

Grid modernization investments can be generally divided into two categories, utility-facing and customer-facing investments. Utility-facing grid modernization initiatives include technologies and projects that help support more efficient and effective operation of T&D systems, including improved reliability, resiliency, and interconnection capacity. Customer-facing grid modernization initiatives include technologies and programs that help support customer adoption of DERs and customer access to third-party service providers and markets.[22]

Figure 3. Grid Modernization Component Example[23]



The significant investment required to modernize the grid to achieve clean energy policy objectives and address climate change impacts has driven the need for comprehensive grid modernization planning and enhanced benefits assessment approaches in many states. This is particularly true for utility-facing grid modernization investments as distribution investments have traditionally been planned over a short-term

[22] Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations, 2021, Tim Woolf, Ben Havumaki, Divita Bhandari, and Melissa Whited, Synapse Energy Economics Lisa Schwartz, Berkeley Lab, p. 3, https://emp.lbl.gov/publications/benefit-cost-analysis-utility-facing

[23] Ibid, p.3. Figure adapted from Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments.

horizon and evaluated based on a best-fit, most-reasonable cost approach, as compared to a BCA for customer-facing investments.

A DOE Guidebook was developed as part of the U.S. DOE Next-Generation Distribution System Platform Initiative. The DOE Guidebook is intended to serve as a reference document for regulators at the state and community levels who are involved in directing or approving GMPs prepared by utilities.[24] The DOE Guidebook includes a chapter devoted to evaluating the cost effectiveness of grid modernization investments that describes the challenges, the importance of objective-driven and planning-aligned investments, and a framework for economic evaluation.

The importance of aligning planned investments to objectives and their expected benefits is described as a critical, best practice as different jurisdictions will identify and emphasize different objectives for modernizing their distribution grids.[25] The prior section followed this best practice describing National Grid's current and proposed ESMP investments and their alignment with the Act's ESMP objectives and benefit areas.

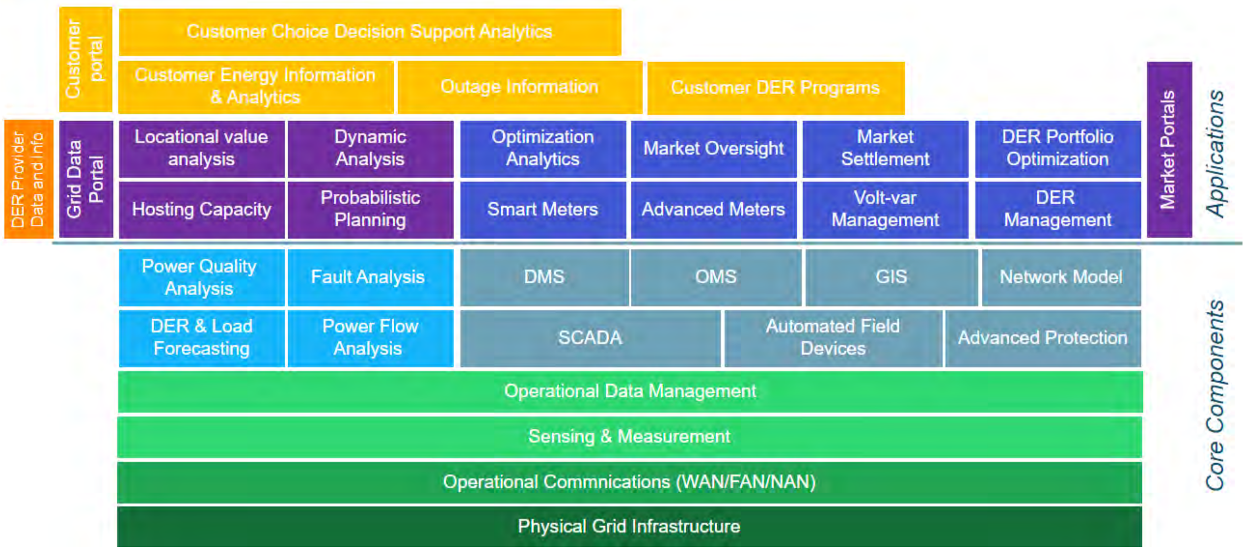
The framework for economic evaluation requires utilities and regulators to categorize investments and to use appropriate methods to evaluate various types of investments.[26] The approach categorizes grid modernization investments by four main investment rationales, or drivers:

- *Joint benefits*: core platform investments that are needed to enable capabilities and functions;
- *Standards compliance and policy mandates*: utility investments that are needed to comply with safety and reliability standards or to meet policy mandates for proactive investments to integrate DERs;
- *Net customer benefits*: utility investments from which some or all customers receive net benefits in the form of bill savings; and
- *Customer choice*: investments triggered by customer interconnection, opt-in utility programs, and customer-driven reliability improvements paid for by individual customers.

The DOE Guidebook provides an example, shown in Figure 4 below, of what capabilities and functions could be considered a grid modernization "core component" (or core platform investment under the joint benefit category above) as compared to an "application" which is enabled and supported by core components.[27] The example provides a starting point for state-specific capability definitions and the application of the economic evaluation framework.

[24] Modern Distribution Grid DSPx, Strategy & Implementation Planning Guidebook Volume IV, Version 1 Final Draft, June 2020, (DOE Guidebook), https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume_IV_v1_0_draft.pdf, p. 4
[25] Ibid, p. 108
[26] Ibid, p. 108
[27] Ibid, p. 59

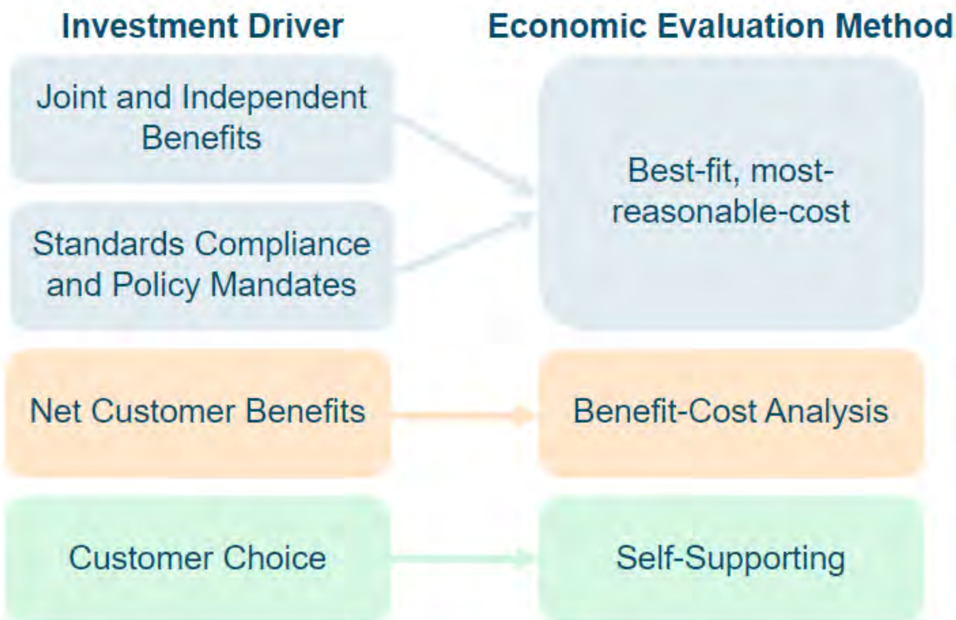
Figure 4. Grid Modernization Technology Stack[28]



In the cost-effectiveness framework, investments that provide joint and interdependent benefits or facilitate compliance with standards and policy mandates are subject to a best-fit, most-reasonable cost standard, which indicates that an investment provides the highest value for a reasonable cost with respect to meeting objectives. Investments that are expected to provide net customer benefits are subject to ex-ante BCA. In this case, a portfolio of investments is deemed cost-effective if its lifecycle benefits exceed its lifecycle costs, and thus the portfolio may be approved or deemed prudent by regulators. Investments that are paid for by customers are "self-supporting" because they are assumed to be cost-effective. The approach is illustrated in Figure 5. The extent to which the best-fit, most-reasonable cost approach or the BCA approach is used will vary across states, depending upon each state's objectives, priorities, and proposed investments.

[28] Ibid, p. 59. Adapted from DOE Guidebook.

Figure 5. Investment Drivers and their Economic Evaluation Methods[29]



Massachusetts Benefits Assessment Context

Several progressive climate policy states, including Massachusetts, have established GMP filing requirements and adopted benefit assessment requirements aligned with the DOE Guidebook framework. The Massachusetts Department of Public Utilities (MA DPU) established requirements for the first grid modernization filing in a June 2014 order.[30] The order required each EDC to submit a 10-year GMP outlining how each EDC proposes to make measurable progress towards the MA DPU's grid modernization objectives. In their GMPs, EDCs must outline their timing and priorities for all their grid modernization planning and investments over the 10-year period. The companies also must include a 5-year short-term investment plan (STIP), which applies only to a company's capital investments. Capital investments included in the STIP must be supported by a comprehensive business case analysis including a BCA.[31] Capital investments contained in the STIP, made during the first five years of the GMP, are eligible for pre-authorization. The MA DPU approved specific grid modernization investments in 2018 from the EDC's initial filings.

The MA DPU subsequently established a second GMP term to encompass calendar years 2022 through 2025 and directed each company to submit a 2022-2025 GMP by July 1, 2021, consistent with the DPU's

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[29] Ibid, p. 113. Adapted from DOE Guidebook.
[30] D.P.U. 12-76-B Order, Grid Modernization Framework
[31] D.P.U. 12-76-C Order, Guidance on the requirements for the business case filings.

directives on the form and content established for these plans.[32] The DPU required that each plan include: 1) a 5-year strategic plan that included a plan for the full deployment of advanced metering functionality; 2) a separate 4-year STIP for grid-facing and customer-facing technologies; and 3) a composite business case in support of both short-term investment plans. Additional investments from these filings were approved in 2022.

In combination, the approved, preauthorized investments are extensive, and the most comprehensive portfolio of investments authorized through GMP filings and supported by a BCA in the U.S.[33] The EDC preauthorized investments include core AMI investments, advanced distribution management (ADMS), communications, monitoring and control, VVO, advanced distribution automation, IT/OT, workforce management, probabilistic power flow, interconnection automation, distributed energy management (DERMS), evaluation and program management, DERMS demonstration, and DER mitigation.

Additionally, several other investment areas included in the ESMP have been justified through a BCA. This includes the EE and EV programs.[34] A summary of the most recent GMP, AMI, EE, and EV BCAs are summarized in the following section.

Summary of National Grid's Previous BCAs

In past filings, National Grid has conducted BCAs for its GMP and its AMI, EE, and EV programs. Each of the BCAs demonstrates that the investments provide net benefits to customers. The BCAs cover many of the ESMP benefits but differ on which benefits are quantified based on the focus of the investments and the expected benefits. The ESMP benefits included in the BCAs are shown in Table 13 by the benefits named in the BCA.

Not all the benefits reviewed in this report have been quantified by National Grid. Avoided renewable energy curtailment creates downstream benefits that are not quantified separately but are included in reduced GHG emissions and health benefits that are captured in existing BCAs. Safety and mitigation of land use impacts are not traditionally measured and are difficult to compare to a counterfactual and, therefore, have not been quantified. Economic development and jobs impacts are challenging to measure because of the wide-reaching impacts, high level of uncertainty, and difficulty in attributing impacts to specific investments.

[32] D.P.U. 20-69, Established the form and content for the EDC's second GMP filing.
[33] GMP filing and approval approaches in other U.S. jurisdictions are summarized in Appendix 1.
[34] Phase II EV Programs

Table 13. Map of ESMP Benefits to National Grid BCA Benefits

ESMP Benefit	Quantified BCA Benefit	GMP	AMI	EV	EE
Reduced GHG Emissions & Climate Change Mitigation	GHG Emission Reduction	✓	✓	✓	✓
Improved Health from Reducing Air Pollutants	Avoided SOx, NOx, and PM10 Emissions	✓			✓
Economic Development and Workforce Impacts					
Grid Reliability and Resilience	Avoided Power Interruptions	✓	✓		
Safety					
Integration of DERs	Distributed Energy		✓		
Transportation & Building Electrification	Net Annual Fuel Savings			✓	✓
	Demand Reduction		✓		✓
	Building Renovations				✓
Avoided Renewable Energy Curtailment					
Mitigation of Land Use Impacts					
Mitigation of Customer Bills	System Optimization	✓	✓		✓
	Electricity Cost Savings		✓		✓
	Avoided Capital Costs	✓	✓		✓
	Avoided O&M Costs	✓	✓	✓	✓

Summary of Previous BCA Results

The net present value of the benefits, costs, and net benefits for the base scenarios of National Grid's previously filed BCAs are summarized in Table 14. The EV BCA presents the benefits and costs on a per vehicle basis rather than a total for National Grid's service territory, so it is omitted from the table. Further descriptions of each analysis are provided below.

Table 14. National Grid BCA Results

National Grid BCA	BCA Term	Benefit ($millions)	Cost ($millions)	Net Benefits ($millions)	Docket No.
GMP	2022-2041	$1,300	$700	$600	DPU 21-81
AMI	2023-2042	$700	$500	$200	DPU 21-81
EE	2022-2024	$4,500	$1,300	$3,200	DPU 21-128 (Electric)

Grid Modernization Plan

The GMP lays out a five-year strategic plan to make measurable progress towards

1. Optimizing system performance by attaining optimal levels of grid visibility, command and control, and self-healing;
2. Optimizing system demand by facilitating consumer price responsiveness; and
3. Interconnecting and integrating DERs.

Three main categories of benefits were quantified: 1) Avoided operations and maintenance (O&M) and Capital Costs, 2) Customer Benefits (energy savings, reliability, etc.), and 3) Societal Benefits. The costs include 1) Advanced Field Devices, 2) Control Center and Back Office, 3) Telecommunications, 4) Modular Optimizing Applications. The costs and benefits are estimated over a 20-year period. Most costs occur throughout the program based on deployment schedules. Most benefits occur in the later years due to steady deployment of grid modernization and its associated benefits. Simple payback is estimated to be achieved in less than nine years.

Advanced Metering Infrastructure

The AMI implementation plan includes a high-level BCA determining the cost effectiveness of full-scale AMI deployment. The BCA considers a 20-year timeframe. The costs are broken out into five main categories: 1) AMI Meters and Communications (Capital), 2) Service Company IT, 3) Other Capital, 4) Program Operating Cost, and 5) Run-the-Business. The costs for setting up back-office and IT systems appear in the first 18 months. Years 3-5 show a spike in capital and installation costs associated with meter deployment. The annual costs drop to stable levels in years six and beyond. The quantified benefits include: 1) Avoided O&M and Capital Costs, 2) Customer Benefits, 3) Societal Benefits, and 4) Revenue Benefits. Large benefits from avoided automated meter reading costs drive early year benefits. After the initial meter installation, there are significant operation and maintenance savings in each subsequent year. The sensitivity that has the largest impact on customer benefits is the assumed customer participation in Time-Varying Rates.

Energy Efficiency

The building sector is the second largest source of GHG emissions.[35] The BCA describes investments in building electrification and EE across three sectors: residential, income-eligible, and commercial. Costs studied include equipment costs, building renovations, and residential behavior education. Benefits are quantified based on GHG emissions savings and fuel savings from decreased heating and electricity usage. Costs and benefits are evaluated over a three-year planning horizon from 2022-2024. Program benefits and costs increase annually between 2022 and 2024. Estimated benefits are greater than program spending for all studied years.

Electric Vehicles

A lifetime BCA framework for National Grid's Massachusetts service territory was created. Costs and benefits of LDVs and medium-duty vehicles (MDVs) and fleet EV adoption were analyzed for ratepayer, participant, and total resource costs and benefits from 2018 to 2030. Benefits and costs were calculated on a per vehicle basis where federal tax credits, avoided O&M, and fuel savings were quantified as benefits and increased vehicle costs, electricity supply, and charging costs were quantified as costs. Net benefits outweighed the costs per vehicle in all scenarios studied, with the greatest net benefits in fleet LDVs and MDVs because of their higher fuel and O&M savings. Additionally, benefits from reduced emissions were also quantified, showing over $370M in abated emissions costs over the 12-year timespan. Capital costs to support adoption of EVs increase with time as necessary charging infrastructure is constructed, but eventually plateaus and begins to decrease as 2030 is approached. Annual utility revenue increases annually as EV charging becomes more common.

2050 Benefit Outlook

The ESMP investments in this report will continue to deliver benefits to the grid and Massachusetts consumers beyond the 5- and 10-year timeframe given their foundational nature. The Commonwealth's electric grid loads, load patterns, and resource mix is poised to change drastically in the next 15-20 years en route to the state's Net Zero by 2050 target. National Grid predicts that the gap between summer and winter peak will close by 2034 Figure 6.[36] Our own work predicts that New England will become a winter

[35] Massachusetts Clean Energy and Climate Plan for 2025 and 2030, 2022, https://www.mass.gov/doc/clean-energy-and-climate-plan-for-2025-and-2030/download, p. 7. Building emissions include residential and commercial sectors.

[36] Electric Sector Modernization Plan Report. Empowering Massachusetts by Building a Smarter, Stronger, Cleaner Energy Future for All Bay Staters, National Grid, 2023.

peaking system around 2030 and that peak load could double by 2050 compared to current peaks, as shown in Figure 7.[37]

Figure 6. National Grid's Historical and Forecasted Aggregate Peak Demand for Summer and Winter[38]

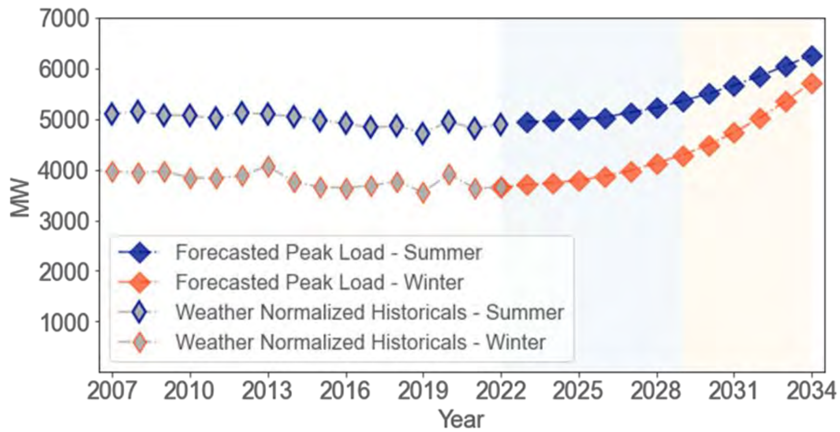
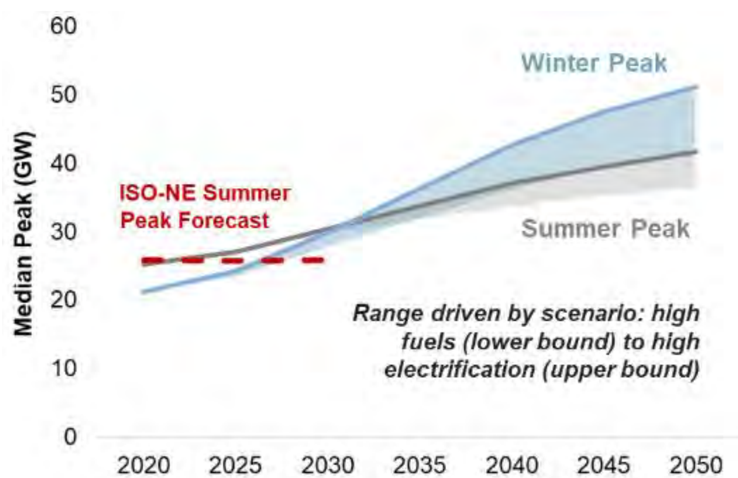


Figure 7: Electric Peak Load Forecast[39]



These load increases will be driven primarily by electrification of space heating and transportation loads. On the supply side, Massachusetts' clean energy goals are expected to move the state's electricity mix towards clean or low-emissions resources while meeting these increasing loads.

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[37] Net-Zero New England: Ensuring Reliability in a Low-Carbon Future, November 2020, Energy and Environmental Economics, and Energy Futures Initiative, https://www.ethree.com/wp-content/uploads/2020/11/E3-EFI_Report-New-England-Reliability-Under-Deep-Decarbonization_Full-Report_November_2020.pdf

[38] Electric Sector Modernization Plan Report. Empowering Massachusetts by Building a Smarter, Stronger, Cleaner Energy Future for All Bay Staters, National Grid, 2023.

[39] Net-Zero New England: Ensuring Reliability in a Low-Carbon Future, November 2020, Energy and Environmental Economics, and Energy Futures Initiative, https://www.ethree.com/wp-content/uploads/2020/11/E3-EFI_Report-New-England-Reliability-Under-Deep-Decarbonization_Full-Report_November_2020.pdf

There is some uncertainty in the makeup of future generation portfolios. For example, long-distance transmission investments are needed for load pockets such as the Greater Boston Area to access renewable energy in Western Massachusetts or high-quality wind in Northern Maine. But given the difficulty of building transmission, especially in land-constrained areas such as New England, transmission may not be successfully built. Similarly, while offshore wind projects are being built at a much greater rate than ever before, there is a chance that the rate and scale of deploying this relatively new technology may not keep pace with the trajectories suggested by state clean energy plans.

Independent of this uncertainty and the corresponding fractions of clean energy and fossil resources on the future grid, the ESMP investments will deliver benefits in the 2050 timeframe. Some benefits, such as the reduced customer outage time afforded by FLISR, do not depend on generation mix. In fact, the role of FLISR may become more important with increasing storm intensity due to climate change. Other benefits, like reduced energy consumption through VVO or EE, play an important role in mitigating future load growth with efficiency. Benefits like improved real-time control and visibility through ADMS and DERMS enable operators to plan and operate the grid optimally. And the ability to interact with customers and their usage through AMI provides an ability to align usage with intermittent supply that will increase with higher penetrations of programmable devices. With the entire suite of ESMP investments, enablement of electrification, DER integration, and the resulting capacity and energy savings will continue to deliver significant cost savings to customers, reduced emissions, and added reliability and resilience in any future.

Conclusions

To achieve Massachusetts' Net Zero by 2050 climate goal and nearer term interim targets, National Grid is investing in its distribution system as part of its ESMP. The ESMP spans investments in Network Infrastructure, Technology Platforms, and Customer Programs that will upgrade physical infrastructure, modernize technology and equipment, and support customer adoption of DERs. The investments include foundational infrastructure and software for National Grid's operations and programs and applications to achieve specific goals that together will enable a multitude of benefits.

National Grid's ESMP investments enable significant climate, health, economic, and grid benefits. The investments will enable more clean energy resources to replace fossil fuels, reducing GHG emissions to mitigate climate change and reducing air pollution to improve public health. Grid infrastructure investments and technology and customer programs will lead to job growth for the clean energy sector in the Commonwealth and beyond. The investments will also increase grid reliability and resilience, improve grid safety, enable greater integration of DERs, and facilitate the electrification of buildings and transportation. Integration of DERs and electrification will, in turn, mitigate land use impacts by avoiding additional build out of large-scale generation and infrastructure and help avoid the curtailment of renewable energy. Finally, the ESMP investments will mitigate the impacts of these investments on customer energy bills by enabling grid operational cost savings and engaging customers in new products and services to reduce their energy consumption and costs.

Appendix

A.1. Benefit Assessment Approaches in Other U.S. Jurisdictions

Several progressive climate policy states, including Massachusetts, have established GMP filing requirements and adopted benefits assessment requirements aligned with the DOE framework described in the Benefits Assessment Framework section of this report. The following is a summary of the approach in several states that provides context for Massachusetts' benefit assessment filings.

California

Utilities are required to file a GMP that includes a 10-year grid modernization vision and investments over the three-year general rate case (GRC) funding cycle as part of their GRC.[40] GMPs must be considered holistically, accounting for reliability and safety objectives as well as the objective of integrating DERs. The investment scope is focused on utility-facing investments and includes specific technologies listed in the California Public Utilities Commission (CPUC) decision. The 10-year grid modernization vision must identify the entire proposed investment program, what portion was completed in previous GRC cycles and at what cost, and what portion is necessary to complete within the next three-year cycle and thereafter.

Utilities must demonstrate that the investments meet distribution planning objectives at the lowest possible cost in their requests for recovery. The CPUC declined to require utilities to make a cost-effectiveness showing to justify grid modernization investments. The utilities are also required to explain what drives the need for each type of grid modernization investment as part of their justification.

Hawaii

The Hawaiian Public Utilities Commission (HPUC) approved the Hawaiian Electric Company (HECO) Grid Modernization Strategy and Roadmap[41] after extensive stakeholder engagement.[42] The Grid Modernization Strategy includes both utility and customer-facing investments over a 5-year period. HECO is required to file applications to implement the Strategy. HECO's Phase 1 plan which included advanced meters, a meter data management system, and a scalable telecommunication network was approved and justified based on a best-fit reasonable cost approach.[43] HECO is required to track investment benefits and costs on a going forward basis.

HECO filed a Phase 2 Grid Modernization implementation application that included investments in ADMS and distribution field devices, including remote intelligent switches, remote fault indicators, SVCs, and

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[40] CPUC Decision on Track 3 Policy Issues, Sub-Track 2 (Grid Modernization), Decision 18-03-023, 2018, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M212/K432/212432689.PDF

[41] Docket No. 2017-0226, Modernizing Hawaii's Grid For Our Customers (hawaiianelectric.com)

[42] Docket No. 2017-0226, Decision and Order No. 35268, 2018, Instituting a Proceeding Related to The Hawaiian Electric Companies' Grid Modernization Strategy

[43] Docket No. 2018-1141, 2018, Grid Modernization Strategy Application (hawaiianelectric.com)

line sensors.[44] The filing applied the same economic evaluation framework as the DOE Guidebook framework claiming the investments fall within the standards and safety compliance and policy compliance categories and should be evaluated from a best fit, reasonable cost basis. The Phase 2 application docket is currently suspended to provide time for Phase 1 implementation progress to provide valuable data and learnings to inform Phase 2's evaluation and implementation.

Minnesota

The Minnesota Public Utilities Commission requires Xcel Energy to file an integrated distribution plan (IDP) every year.[45] Among other information, the plan must include a 5-year action plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and DER future scenarios. The plan must also provide detailed support for its proposed grid modernization investments, including assessment of both quantitative and qualitative benefits for each investment.

Xcel filed its second annual IDP[46] in November 2019 that included several grid modernization investments referred to as its Advanced Grid Intelligence and Security (AGIS) proposal. The AGIS components included AMI, Field Area Network, Integrated VVO, and FLISR. Xcel provided a BCA for the portfolio of investments and each investment separately. Xcel plans to request recovery through either the IDP filings or as part of a GRC.

New York

Utilities are required to file a GMP[47] with the New York Department of Public Service (DPS) every two years that describes the investment plan (without cost estimates) and progress to date. The DPS provides specific requirements for every filing, including the investment areas to be covered which include both utility and customer-facing initiatives. The GMP does not include cost estimates and is not a request for approval but is used to support specific investment requests in multi-year rate case filings or separate petitions for pre-authorization spending approval.

The DPS has developed a standardized benefit-cost analysis framework and requires each electric utility to file a BCA Handbook[48] semi-annually in conjunction with its GMP filing. The purpose of the BCA Handbook is to provide a common methodology for calculating benefits and costs of projects and investments. The BCA Order requires that a benefit-cost analysis be applied to the following four categories of utility expenditure:

- Investments in distributed system platform (DSP) capabilities

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[44] Docket 2019-0327, 2019, [Application of Hawaiian Electric Companies Limited Verification Exhibits A-K]

[45] MNPUC, Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy, Docket No. E-002/CI-18-251, [searchDocuments.do (state.mn.us)]

[46] Integrated Distribution Plan (2020 – 2029), Docket No. E002/M-19-666

[47] Con Edison Distributed System Implementation Plan, 2023, https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/distributed-system-implementation-plan.pdf

[48] Available by searching for Case 16-M-0411 on the DPS website; https://documents.dps.ny.gov/public/common/search.html

- Procurement of DER through competitive selection
- Procurement of DER through tariffs
- EE programs

With respect to investments in DSP capabilities, to date New York utilities have filed business cases and BCAs for AMI investments that include both utility and customer-facing capabilities. These filings have been approved with the utilities in the implementation phase. It is unclear to what extent BCAs will be required for other utility-facing grid modernization investment proposals as recent rate cases have justified the investments qualitatively. Customer-facing modernization investments, including EV[49] and EE programs, have been justified with BCAs.

[49] Niagara Mohawk 2020 Rate Case, Docket 20-E-0380

Exhibit 9A: Detailed reports on National Grid's Load Forecasting

MASSACHUSETTS ELECTRIC COMPANY

NANTUCKET ELECTRIC COMPANY

2023 to 2050 Electric Peak (MW) Feeder-level Forecast

December 2022

Original: December 16, 2022

Load Forecasting & Analytics

nationalgrid

REVISION HISTORY & GENERAL NOTES

Revision History

Version	Date	Changes
Original	12/16/2022	- ORIGINAL

General Notes:

- Peak load data is October 2022; projections from 2023 forward
- Energy efficiency, electric heating, solar, energy storge and demand response is internal data vintage August 2022.
- Electric vehicle data is POLK data vintage June 2022 with actual to the end of 2021
- 2020 American Community Survey 5-year from U.S. Census Bureau[1]

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[1] https://www.census.gov/data/developers/data-sets/acs-5year.html, retrieved September 2022

CONTENTS

1. Summary

National Grid's Massachusetts electric system serves over 1.35 million customers (approximately 43% residential, 44% commercial, and 13% industrial by energy volume) in the State of Massachusetts. It spans across the entire state, including all or some portions of Berkshire, Bristol, Essex, Franklin, Hampden, Hampshire, Middlesex, Nantucket, Norfolk, Plymouth, Suffolk, and Worcester Counties. The feeder-level forecasts are provided for 987 feeders in the Company's Massachusetts electric system. The forecasting process takes the system-level load growth projection and outlook on distributed energy resources (DER) as inputs. Detail on the system level load forecast and DER projections are in "Massachusetts Electric Company & Nantucket Electric Company 2023 to 2050 Electric Peak Forecast" ("System Level Peak Report"). It then leverages the regional specific factors such as demographic information, land availability, etc. to allocate the system-level forecasts to the feeder level. The DER includes energy efficiency, solar-photovoltaic, energy storage, electric vehicles, and electric heat pumps. This report focuses on discussing the methodologies of developing the feeder-level forecasts.

2. Base Load Forecasting and Profiles

2.1 Base Load Annual Peak Forecast

The base load is defined as the peak load before any *incremental* DER impact; however, it includes historical embedded DER impacts. The historical base load is weather adjusted to reflect the 50/50 and 90/10 weather scenarios[2], and then grow at the same rate as the Power Supply Area (PSA) that it falls into. There are 18 PSA areas in the Company's Massachusetts's service territory, which cover all the 987 feeders that are being forecasted. The PSA-level load growth forecast is discussed in the System Level Peak Report. This process results in a point annual peak base load forecast between 2023 and 2050 for each feeder. The future incremental DER impact is not part of this base load forecasting process and will be adjusted for later in the process.

2.2 Base Load Annual Profile

For each feeder, the point base load forecast of each year is used in an annual hourly load profile to derive the hourly base load profile for each hour of each year through the forecast horizon. First, the annual hourly normalized load profile (i.e., the 8760 load profile) is derived from the typical load shapes from the Company's load research team's work which is published on the Company's data portal[3]. The typical load shapes are available for typical residential, typical commercial, and typical industrial customers, respectively. The feeder-level forecasting work takes the customer type (i.e., residential, commercial, and industrial) mix of each feeder to derive one single weighted

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[2] Normal 50/50 weather is defined as the average weather on the past 20 annual peak days. Extreme 90/10 weather is such that it is expected that it will only be exceeded 10% of the time. Please refer to the System-Level Peak Report for detailed discussions on weather scenarios. The feeder-level work uses the same weather scenario definitions developed for the ISO zone that each feeder falls into. There are three ISO zones that the Company serves in MA including Northeastern MA and Boston area (NEMA), Southeastern MA (SEMA), and West-central MA(WCMA)

[3] https://www9.nationalgridus.com/energysupply/load_estimate.asp, retrieved October 2022

load profile using the load shapes of each customer class and the customer mix, i.e., residential, commercial, and industrial, as the weight as shown in Formula (1) and Figure 1.

$$8760\ Base\ load\ profile = \frac{[(R * LS_r) + (C * LS_c)\ ) + (I * LS_i)]}{(R+C+I)} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (1)$$

where, LS_r = Typical Residential Customers Load Shape,

LS_c = Typical Commercial Customers Load Shape,

LS_i = Typical Industrial Customers Load Shape,

R = number of residential, *C*= number of commercial, *I* = number of industrial customers,

Next, the normalized annual hourly profile is multiplied by the point base load peak forecast to obtain the final annual hourly load profile for each feeder.

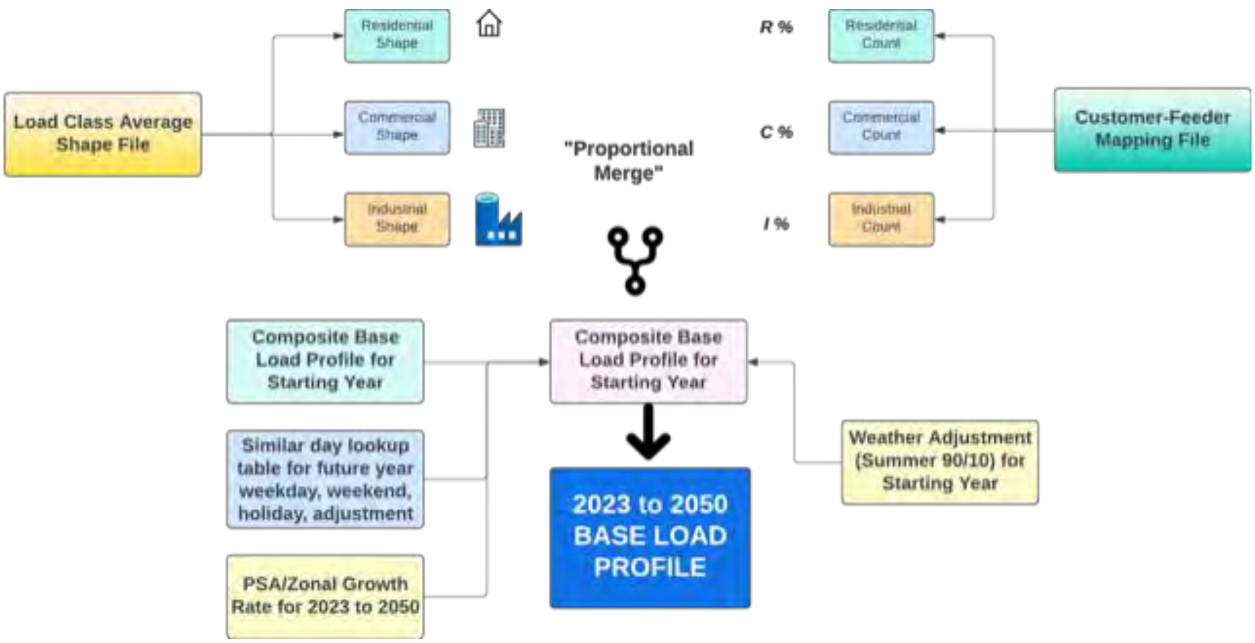

Figure 1: Flowchart of Generating 8760 Profile for the base load

3. Distributed Energy Resource Methodology

This section describes the methodology for allocating the system-level DER forecasts to the feeder level and developing the annual DER load profiles. Since historical DERs are embedded in the historical base load, all DERs are rebased to zero starting in the first forecast year to eliminate double counting of DERs.

3.1 Energy Efficiency

Feeder Level Allocation:

The forecast of annual peak contribution of Energy Efficiency (EE) measured at the Company's Massachusetts electric system level is described in the System-Level Peak Report for base, low, and high scenarios. The system-level EE peak saving is then allocated to different ISO zones in the Company's electric service area based on each zone's peak load contribution to the system. The zonal-level annual incremental EE growth is then allocated to the feeders in the zone based on the annual energy share of each feeder within the zone. The same process is applied to allocate base, high, low EE projections to the feeders to create the base, high, and low EE cases at the feeder level.

Profile Description:

A normalized typical daily profile is assumed for each month of a year. Figure 2 shows the normalized typical daily profile. All days in a year share this same normalized daily profile, however, it is scaled differently for each month based on monthly variation in EE impact. Figure 3 presents the normalized monthly variations of EE savings. EE saving estimations for the typical day profile and the monthly variations are based on the types of EE programs that the Company have customers enrolled in and the typical customer consumption patterns. Figure 4 gives an example of hourly saving through a year at a randomly selected feeder.

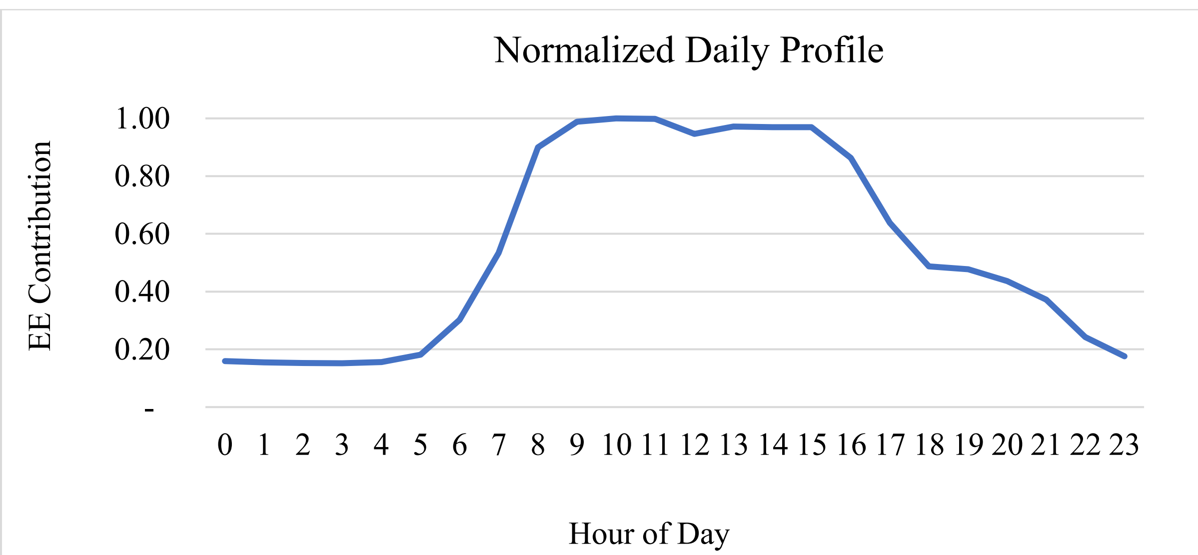

Figure 2: Estimated normalized hourly EE savings

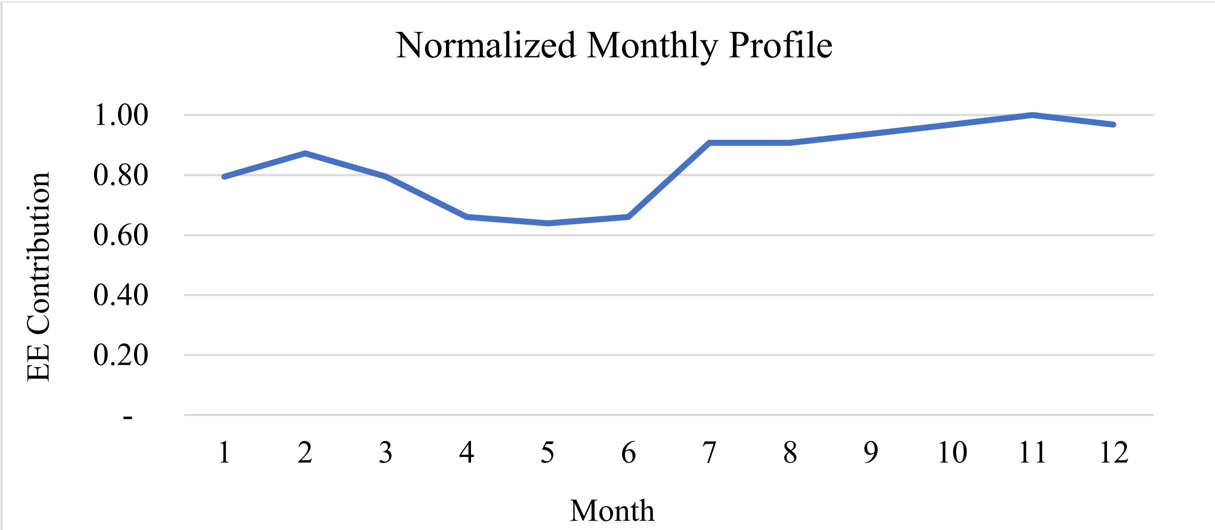

Figure 3: Estimated normalized monthly EE savings

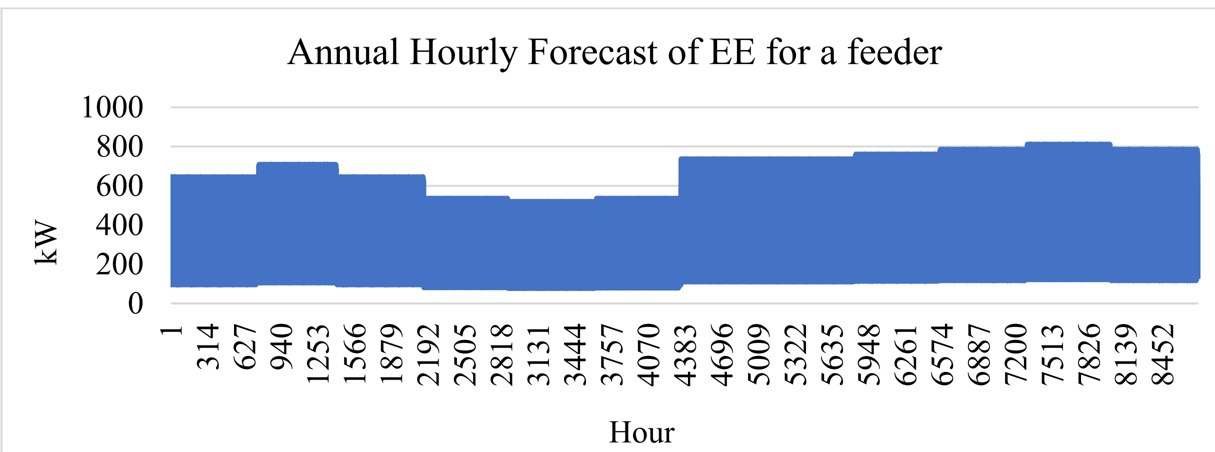

Figure 4: Estimated hourly EE saving (kW) at a randomly selected feeder

3.2 Rooftop Solar-Photovoltaics

The system-level rooftop PV nameplate projection is first allocated to electric customer accounts that the Company serves. Then, the customer account level projection gets aggregated to each feeder from which these accounts get fed. The process of allocating system-level projection to the customer account level starts with scoring electric customer accounts[4] for their likelihood of adopting rooftop PV. The score considers factors including but not limited to household income, employment stability, homeownership/renter status, etc. For example, homeowners with higher household incomes and more stable employment status are more likely to become PV adopters and thus have higher scores. All the customer accounts are scored and ranked from the most likely

[4] Customers who have already adopted rooftop PV are excluded from the allocation process.

adopters to the least likely adopters. The system level projection is allocated to top-ranked customer accounts until the total allocated nameplate kW reaches the system-level projection.

The hourly impact of rooftop PV is estimated from using a typical meteorological year from National Renewable Energy Laboratory (NREL)[5] to convert nameplate to power generation.

3.3 Non-Rooftop Solar-Photovoltaic

For the near term, the non-rooftop PV nameplate projection is based on projects in the application queue and their estimated connection date. The annual aggregated incremental nameplate connection is bounded by the system-level projection.

After this and for the period between the late 2020s and 2050, the system-level annual incremental projection is allocated to the available land parcels that are most likely to develop PV. Available land parcels are ranked by their likelihood to develop PV and then the system-level projection is allocated to the highest ranked parcels each year until the system-level projection is met. The Company leverages the renewable interconnection analysis tool developed by GridTwin[6] for analyzing land parcel availability and ranking PV projects. The GridTwin tool considers land availability based on land use codes, environmental and cultural restrictions, as well as land characteristics (e.g., slopes). It ranks available and suitable land, by calculating the Internal Rate of Return (IRR) to rank the profitability of developing PV projects on each land parcel. The compensation components considered in the IRR calculation are primarily based on incentives from MA SMART programs. The cost components considered in the IRR calculation include land cost, interconnection cost, capital cost, and annual operation & maintenance costs.

The hourly impact of non-rooftop PV is estimated from using the same typical meteorological year weather from NREL as rooftop PV to convert nameplate to power generation.

3.4 Storage

For the near term, the storage projection is based on projects in the application queue and their estimated connection date. In the medium and long term, the storage projection assumes achieving the State's decarbonization policy target. This results in a storage projection reaching about 18% of the estimated PV connection.

A peak shaving storage discharging profile is assumed thus the storage is expected to discharge during typical peak hours in a day and charge during the hours when PV is expected to generate or late-night hours.

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[5] https://nsrdb.nrel.gov/data-sets/tmy, retrieved September 2022
[6] https://gridtwin.energy/

3.5 Light-duty Electric Vehicles

Allocation Overview

The Light Duty Electric Vehicle (LDEV) forecast includes charging demand for both battery electric vehicles (BEV) and Plug-in Hybrid Electric Vehicles (PHEV). The allocation process takes the system-level LDEV adoption projection for the whole service territory and identifies where and when the adoption will happen at the more granular feeder level. The majority of the light-duty EVs are for personal use or are being allocated to residential customers, while about 6%[7] of the total projected number of light-duty EVs are expected to be for commercial use and are being allocated to commercial and industrial customers. For residential LDEV, we use a study of the propensity for EV adoption to forecast the annual increment in EV adoptions and charger installation, inputs for such models are state-level projections for long-term LDEV growth provided as described in the System Level Peak Report. The Zip Code Tabulation Areas (ZCTA)-level socio-economic information[8] is primarily utilized for the propensity model, and the key variables are median household income, the fraction of individuals with degrees that are higher than college, and commuting patterns. If a feeder serves multiple ZCTAs, we compute the weighted average score with the number of residential accounts as weights. Overall, neighborhoods with higher income level, higher education rates and higher are projected toexperience higher adoption. As for commercial light-duty EVs, the annual incremental vehicle adoption for each feeder is proportional to the number of Commercial and Industrial customers on each feeder.

Profile Description

As the EV adoption rates increase, the annual energy demand which is primarily determined by the vehicle miles traveled (VMT) for electric vehicles also shifts. Figure 5 shows the temporal progression of the energy demand per LDEV in kW throughout 2050 that are from NHTSA (National Highway Traffic Safety Administration)[9]. We can see that the VMT-driven annual demand steadily increases until 2040 and remain stable after that.

[7] https://www.iso-ne.com/static-assets/documents/2021/12/lf2022_draft_transp_elec.pdf, ISO-NE, December 2021
[8] https://www.census.gov/data/developers/data-sets/acs-5year.html, retrieved October 2022
[9] https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/809952, retrieved July, 2022

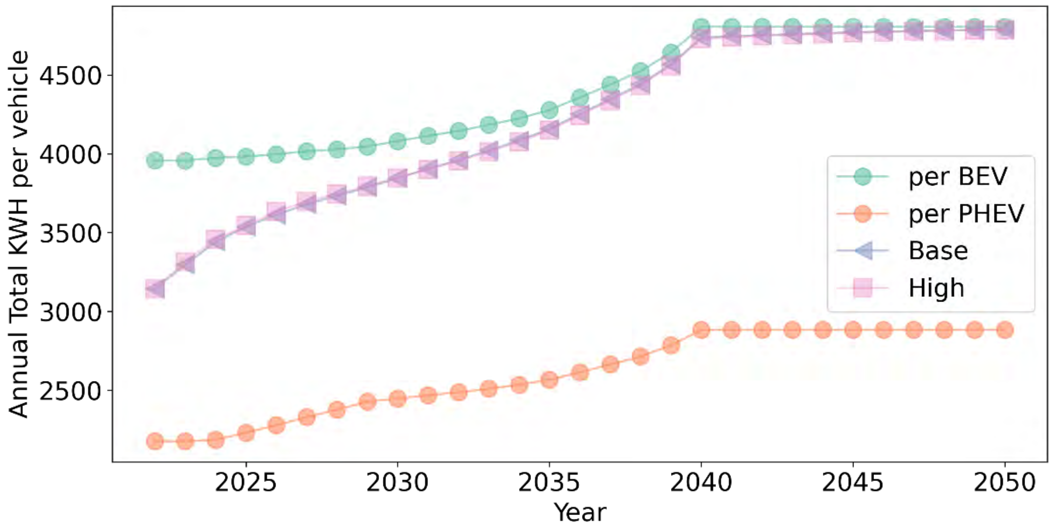

Figure 5: Annual Energy Demand per Light Duty EV

We then leverage the charging profiles and temporal patterns developed by ISO-NE[10] and BloombergNEF (BNEF)[11] to project the charging demand for different charging location types (home/work/public) at different times and aggregate them to the corresponding feeder. Figures 6 and 7 below depict the detailed charging demand for both managed and unmanaged charging scenarios. In the unmanaged scenario, a dual peak pattern is observed on weekdays with the evening peaks (between 7 and 9 PM) generally larger than the morning peaks. However, the evening peak shifts to 10 PM in the managed charging profile. The managed charging scenario assumes 75% of the LDEV owners have access to the home chargers, and 75% of those do not charge their vehicles at home during the peak hours (4PM to 10PM). Away-from-home charging is assumed to remain unmanaged.

[10] https://www.iso-ne.com/static-assets/documents/2021/12/lf2022_draft_transp_elec.pdf, retrieved December 2021
[11] https://about.bnef.com/electric-vehicle-outlook/, retrieved June 2022

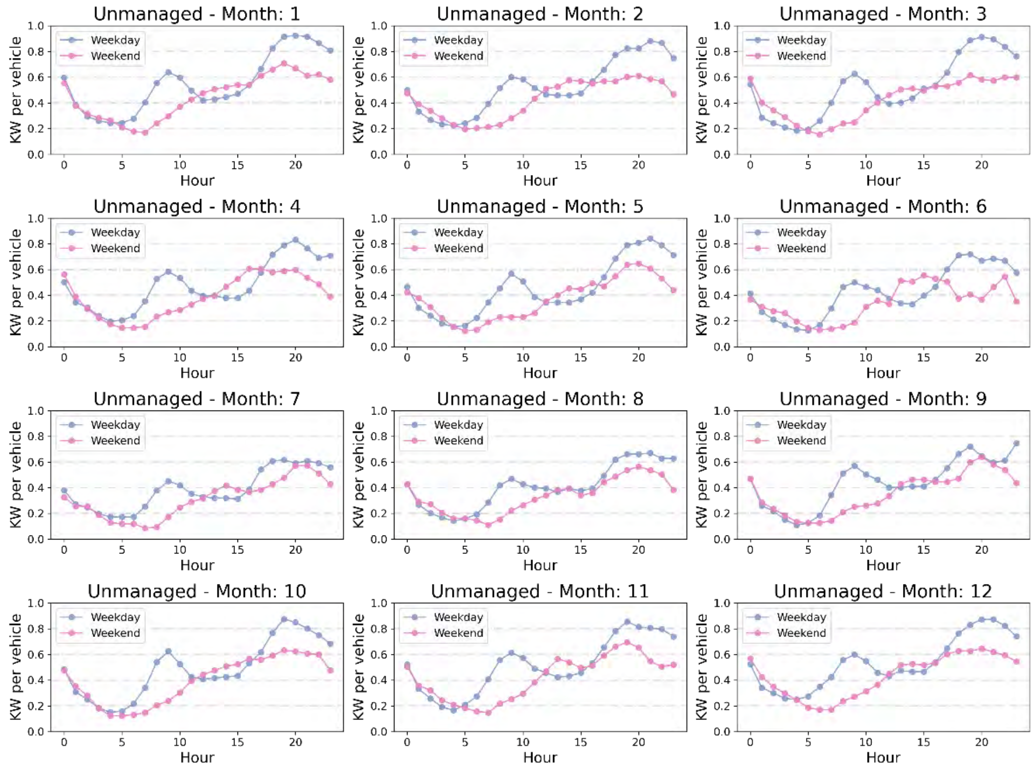

Figure 6: Unmanaged Charging Profiles per LDEV

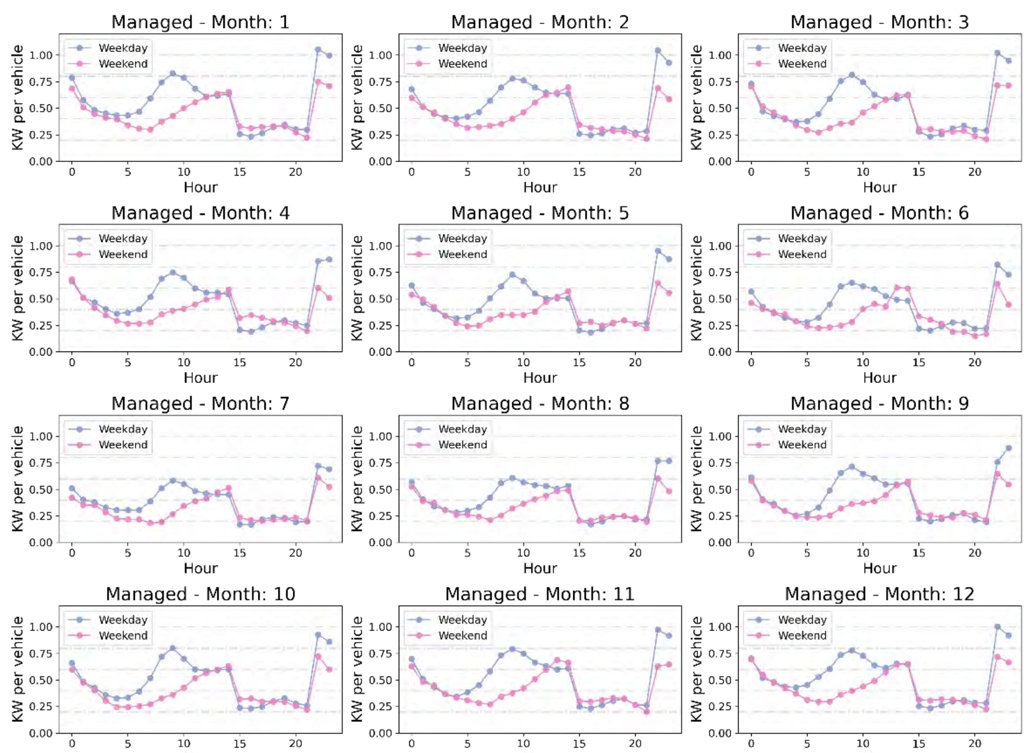

Figure 7: Managed Charging Profiles per LDEV

After estimating the hourly total charging demand for all the electric vehicles, we further break down the charging demand into three categories: home, work, and public charging. The fraction from each category is shown in Figure 8 below and at each hour by leveraging the NREL EVI Pro Lite Load Profile[12] (Scenario 52 with 75% home charging access; minor adjustment on work fraction on weekends have been implemented) by day type and hour of day, such that the sum of all three categories always equals one. We can see that in most hours after 4 PM and before 3 AM on weekdays, home charging is about 80% of all charging. Workplace charging events mostly take place between 6 AM and 2 PM, peaking around 8 AM with a 60% peak. Public charging peaks on weekends around 10 AM. The projected number of workplace and public chargers are provided by an external vendor.

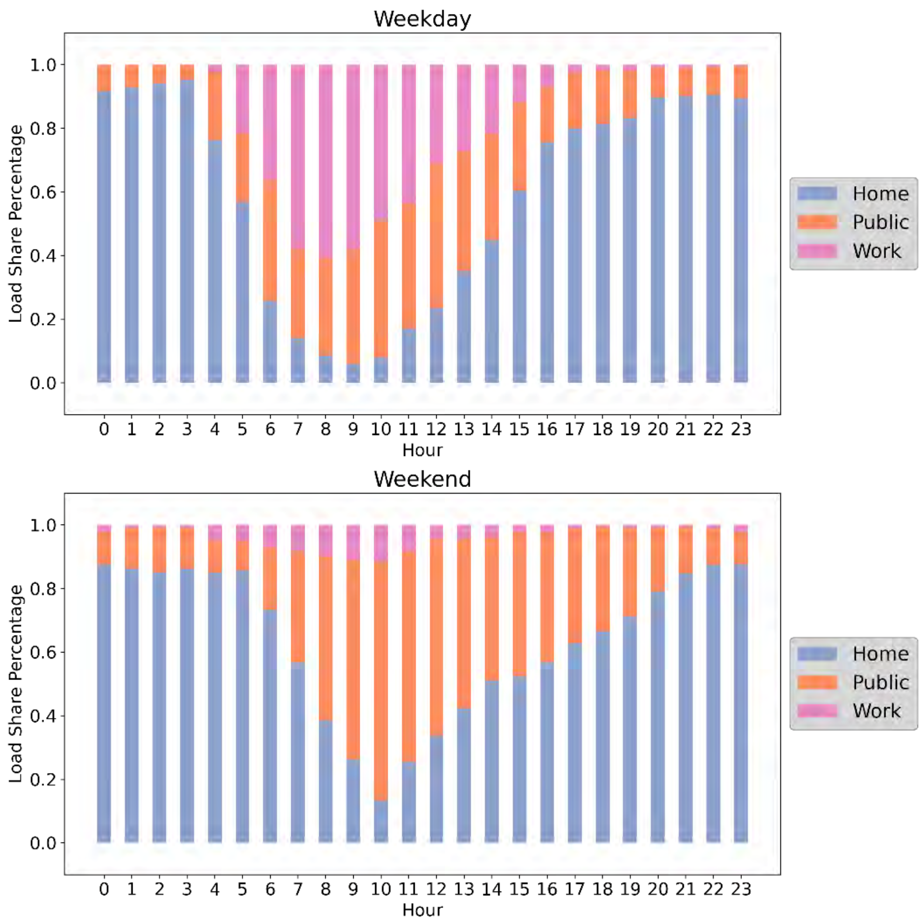

Figure 8: Hourly Charging Demand Allocation based on Charging Type

12 https://developer.nrel.gov/docs/transportation/evi-pro-lite-v1/, retrieved September 2022

3.6 Electric Heat Pumps

Allocation Overview

The electric heat pump allocation process primarily uses the system-level annual forecasted number of heat pumps (see System Level Peak Report), the up-to-date heat-pump adoption records from the Company's Customer Energy Management team (CEM), and the House Heating Fuel type from the Census Bureau on the ZIP Code Tabulation Area (ZCTA) level. For the first five years (2023-2027), we leverage the CEM historical and forecasted heat pump installation information and assume the heat pump adoption will follow the up-to-date heat pump incentive program participation. For the next six years (2028-2033), the allocation is primarily driven by the number of households that use delivered fuel including bottled or tank gas, fuel oil, kerosene, coal, wood etc. The estimation is through a similar ZIP-to-Feeder allocation process and by the end of 2033, it is projected that most of the households with delivered fuel as the main source will have electrified heat. The full electrification of delivered-fuel heating customers takes place during 2034. For the remaining years in the forecast horizon, the heat pump adoption on each feeder is driven by the number of the utility gas heating households.

Profile Description

The seasonal energy consumption of EH were from the Company's CEM team based on estimated consumption of existing EH units connected through the Company's programs. Then, the winter seasonal energy is proportionally allocated to the heating-needed months including all winter months (November to March) and some shoulder months (October, April, and May). This allocation is based the Company's gas customers' heating consumption. The annual energy consumption of a partial heat pump is 4,461 kWh and the annual consumption of a full heat pump is 8,871 kWh. The definition of full and partial heat pump is aligned with the system-level peak forecast: a full application is defined as a heat pump unit that will serve the all the heating and cooling in the building; a partial heat pump is defined as a unit that will supplement existing heating system, as well as cool the home or building during the summer season. The ratio of full-to-partial heat pumps varies between the base, high, and low cases. Figure 9 shows that the average annual energy consumption per heat pump is different for each case because of the shifting ratio. For the low and base, we can see that such number starts climbing after 2030 as the full heat pumps become more prevalent. In the high case we see a drastic rise beginning in 2026 due to accelerated adoption of full heat pumps.

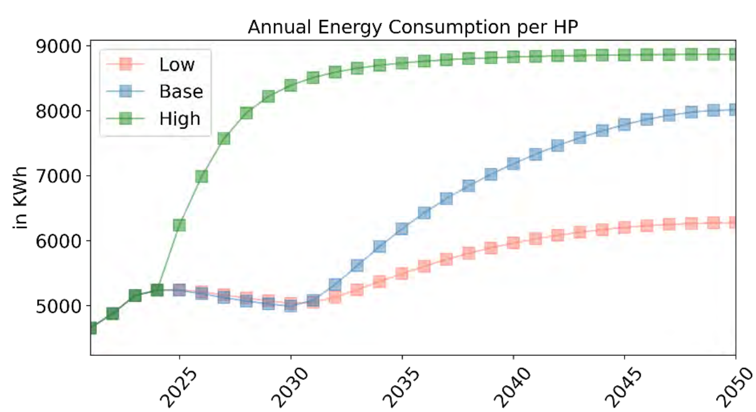

Figure 9: Annual Energy Demand per Heat Pump

Figure 10 below demonstrates the detailed heating/cooling load patterns for both full and partial heat pumps. In the very cold winter months, a dual-peak pattern is observed with morning peaks generally higher than afternoon peaks. Furthermore, the difference between full and partial heat pumps is more pronounced as the partial heat pump in those months is frequently used as a supplementary heating source for zoning or heating individual rooms. We assume there is no demand in the shoulder months of April and October.

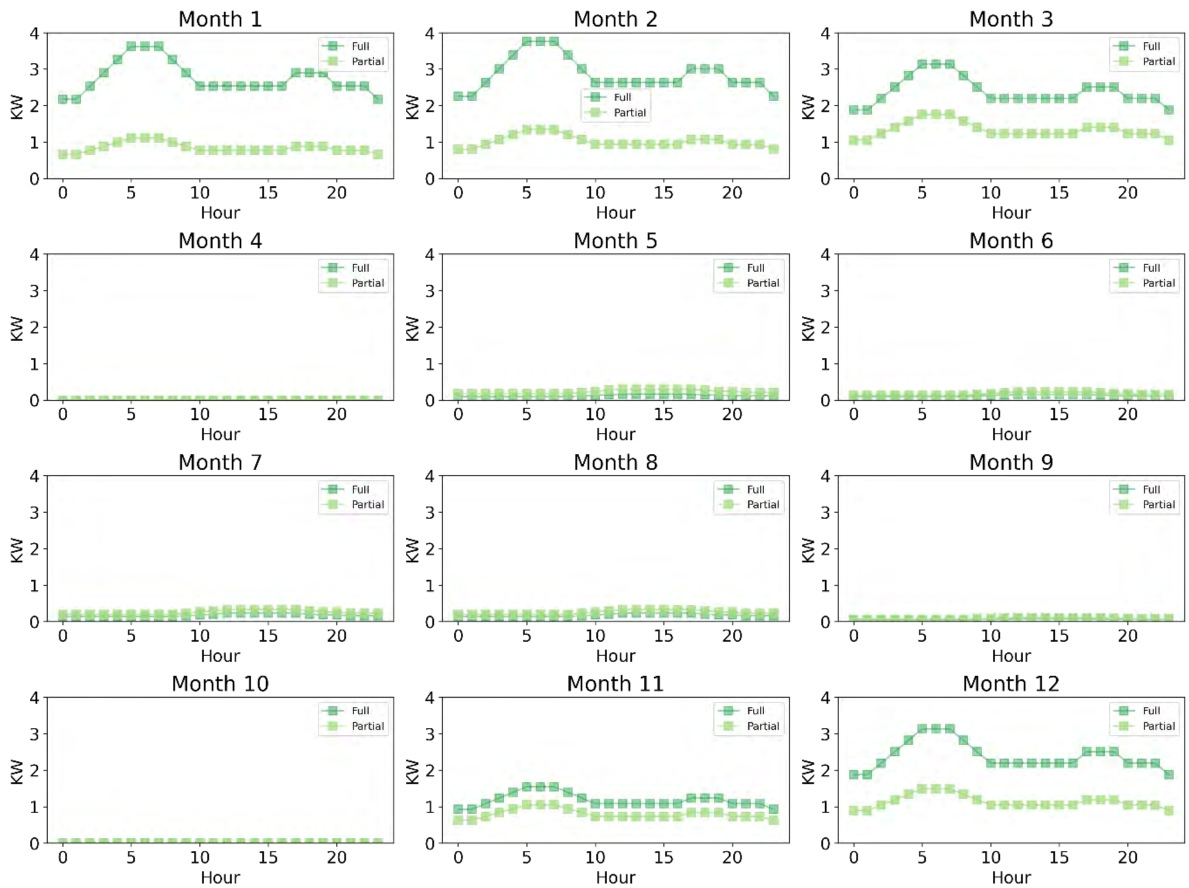

Figure 10: Energy Consumption Profiles per Heat Pump

4. Peak Load Forecast Integration

The projected base load is adjusted for the impact of each DER technology discussed in the previous sections. This generates the post-DER load forecast. Figure 11 shows the distribution of feeders' average annual peak growth rate between year 2023 and 2050. The median of the growth rate is 2.6% and the majority of the feeders have a growth rate ranging from 1% to 4%. High electrification penetration is the main driver of the high growth rates showing on the right tail in the distribution.

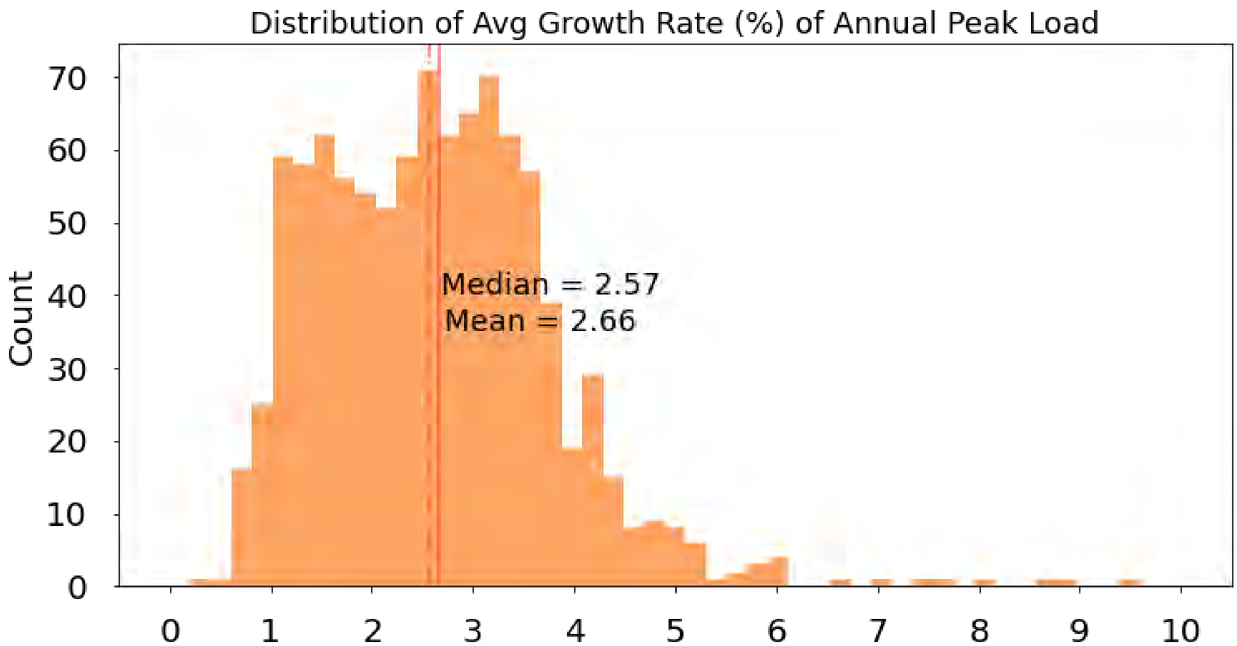

Figure 11: Distribution of average annual growth rates (%)

Figure 12 presents the same average annual growth rate (%) on a map: each marker represents the centroid of a feeder that is forecasted. The growth in the southeast, northeast, and Worcester regions are mainly driven by the EV growth. In the west central area, the current high percentage of delivered fuel as heating source is forecasted to be largely replaced by electric heat pumps thus driving load growth.

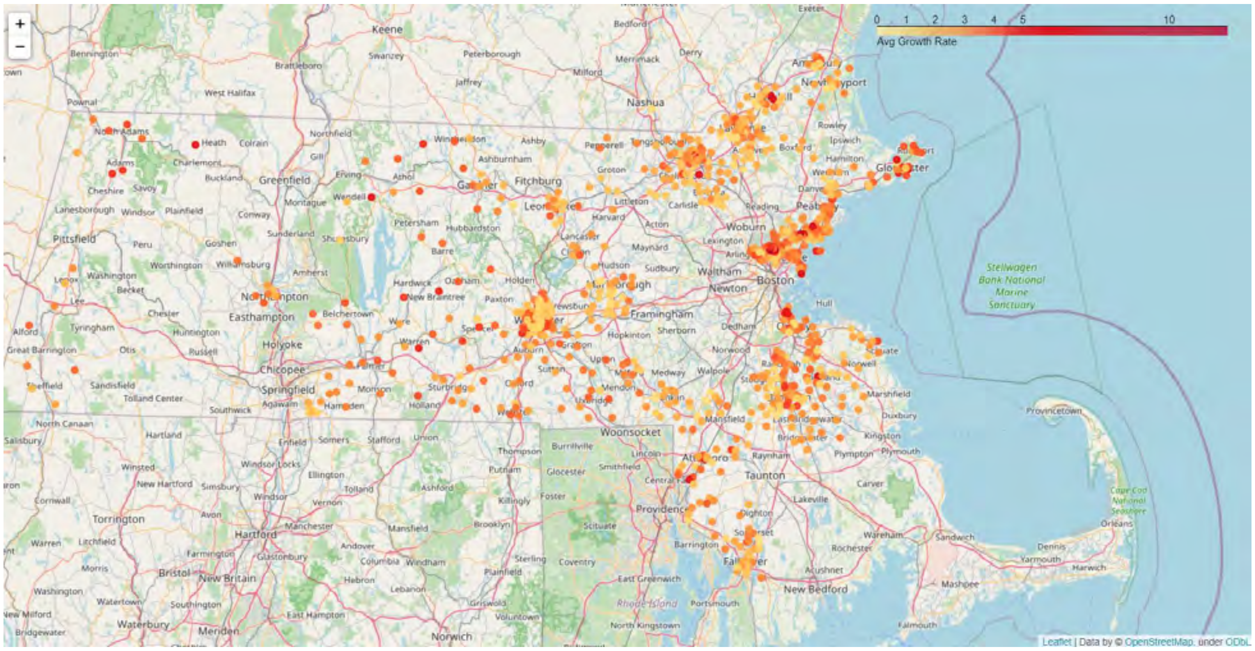

Figure 12: Average annual growth rate (%) of feeders

About 77% of the forecasted feeders are expected to switch to a winter peaking system by 2050. The majority of the switch is expected to occur in the late 2030s and beyond.

Exhibit 9B: Detailed reports on National Grid's Load Forecasting

MASSACHUSETTS ELECTRIC COMPANY

NANTUCKET ELECTRIC COMPANY

2023 to 2050 Electric Peak (MW) Forecast

May 2023

Rev 3, 05/02/2023

Economics and Load Forecasting
Load Forecasting & Analytics

REVISION HISTORY & GENERAL NOTES

Revision History

Version	Date	Changes
Original	11/21/2022	- ORIGINAL
Rev 1	03/01/2023	- added study area forecast
		- updated power supply area forecast
Rev 2	03/15/2023	- updated forecasts with updated EH profile
Rev 3	05/02/2023	- updated study area and power supply area forecasts

General Notes:

- Hourly load data through August 2022; projections from 2022 winter forward.
- Economic data is from Moody's vintage August 2022.
- Energy Efficiency, electric heating, solar, energy storge and demand response is internal data vintage August 2022.
- Electric Vehicle data is POLK data vintage June 2022 with actual to the end of 2021.
- Peak MW and Energy GWH source the ISO-NE/MDS meter-reconciled data (Jan. 2003 to Apr. 2022); internal unreconciled **preliminary** data (May 2022 to Aug. 2022).
- Peak load data is metered zonal load, without ISO bulk system losses.
- References to "Zones" refers to ISO-NE designations; all data is National Grid's service territory information within these zones.
- New this year:
    - Extending forecast horizon to 2050
    - Providing a managed light-duty electric vehicle charging scenario
    - Differentiating electric heat pump by full and partial

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CONTENTS

Summary

National Grid's US electric system is comprised of three companies serving over 3 million customers in Massachusetts and upstate New York. The three electric companies are: Massachusetts Electric Company and Nantucket Electric Company, serving 1.35 million customers in Massachusetts; and Niagara Mohawk Power Company, serving 1.7 million customers in upstate New York. Figure 1[1][2] shows the Company's service territory in the U.S.

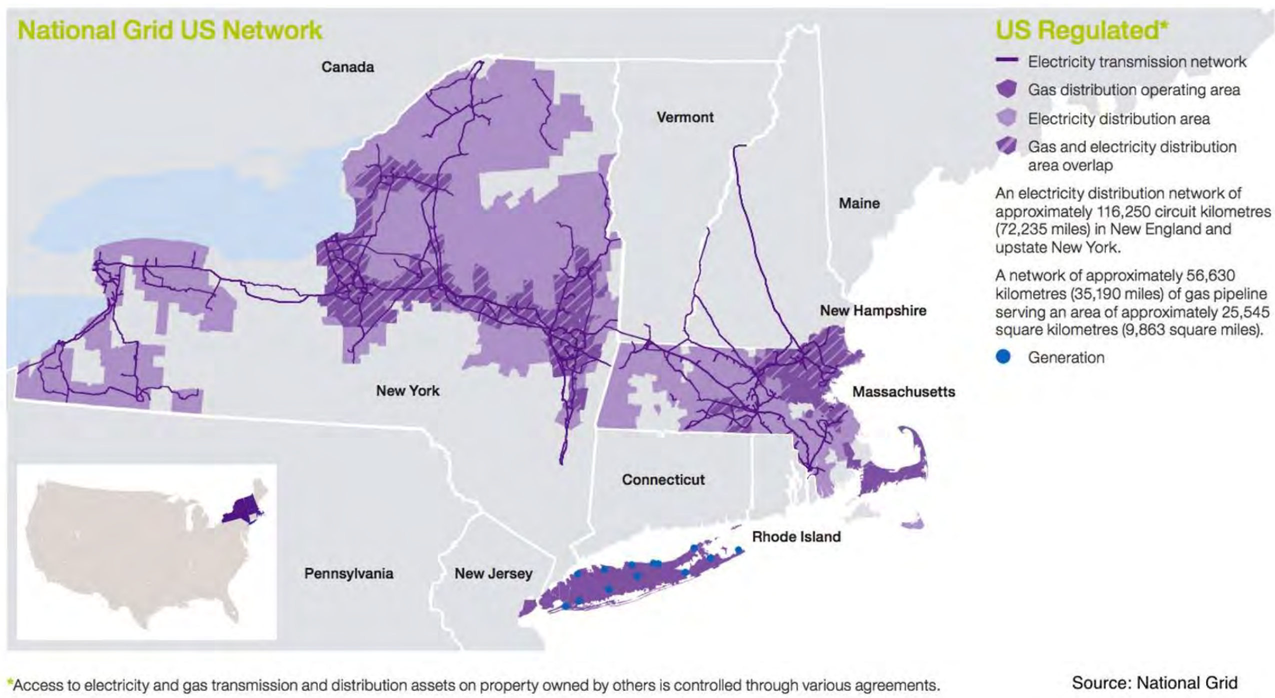

Figure 1: National Grid U.S. Service Territory

Forecasting peak electric load is important to the Company's capital planning process because it enables the Company to assess the reliability of its electric infrastructure, enables timely procurement and installation of required facilities, and it provides system planning with information to prioritize and focus their efforts.

<u>Massachusetts Electric Company (MECO)</u>

MECO's peak demand in 2022 was 4,657.4 MW[3], on Monday, August 8 at hour-ending 18. This 2022 peak was 9.6% below the company's all-time high of 5,152 MW reached on Wednesday, August 2, 2006.

[1] National Grid also serves gas customers in these same states which are also shown on this map.
[2] As of May 22, 2022, National Grid has completed the sale of The Narragansett Electric Company ("NECO") to PPL Rhode Island Holdings, LLC. Thus, Rhode Island is not part of National Grid's U.S. electric distribution system after the completion of the sale.
[3] Meter Data Service's system level PRELIMINARY and subject to change.

This summer's weather for MECO's peak[4] was considered <u>hotter</u> than average (or 'normal'). The peak weather fell in the 88th percentile of peak weather over the last 20 years. This means that 88% of summers had peak weather that was cooler and only 12% of summers had peak weather that was warmer. This year's peak is considered 95.0 MW higher than the peak the company would have experienced under normal weather conditions. Thus, on a weather adjusted "normal" basis this year's peak was estimated to be 4,562.5 MW, an increase of 1.2% compared to last year's weather-adjusted 'normal' peak.

MECO expects slightly growing post-DER peak values – i.e., on average, 0.7% per year, from its 2022 level in the next five years. The system remains summer peaking through the year 2035. However, the peak hour is expected to shift from late afternoon/early evening to later in the evening. During these later hours, EV charging demand increases and PV savings becomes less or not available.
Starting in 2036, MECO is expected to become a winter peaking system. This change is mainly driven by the increasing beneficial electrification in the transportation[5] and building sectors. Figure 2 shows the projected annual peak (solid blue line) and the summer peak (dashed blue line) under the normal weather, as well as the annual peak under two extreme weather assumptions, namely 90-10 and 95-5. Through the forecast horizon, MECO expects an annual growth rate of 3.0% on post-DERs peak under the normal weather assumption.

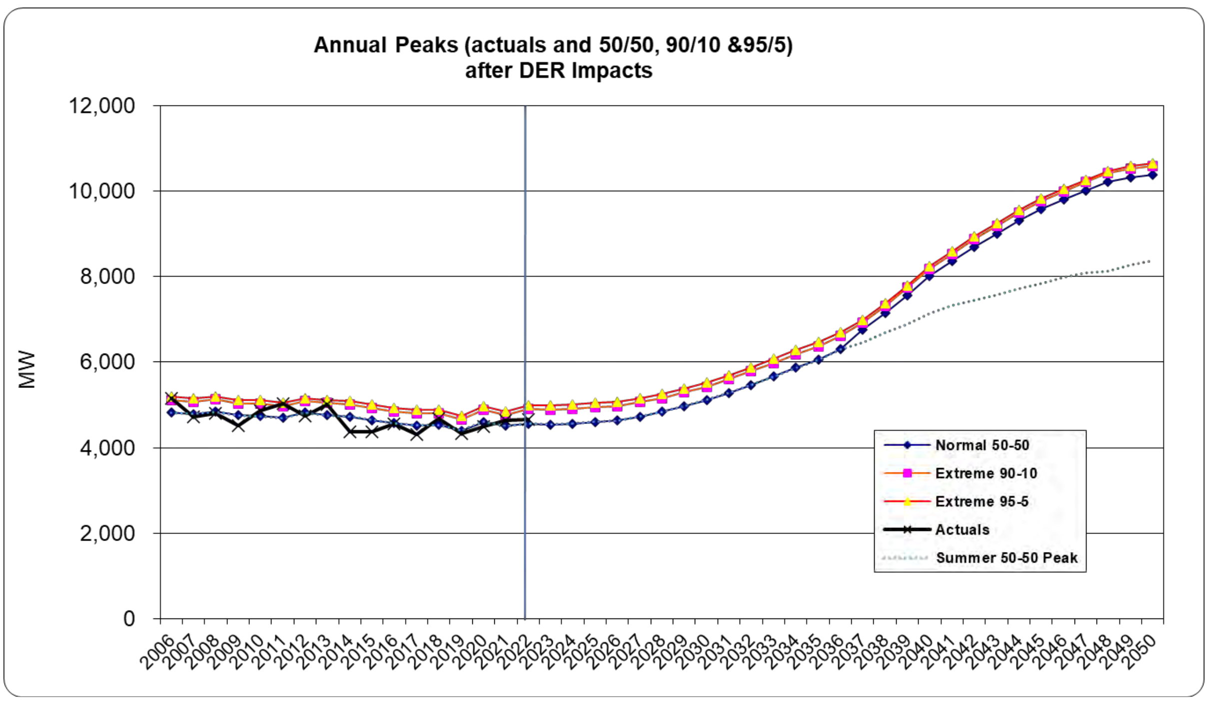

Figure 2: MECO Historical (actual & weather-adjusted) and Projected Peaks

[4] Peaks days, times and weather can vary across the zones which do not always match the same as for the Company.
[5] Managed charging is not considered in the base EV case. A managed charging scenario is considered in the low EV case.

Nantucket Electric Company (NANT)

Nantucket's peak demand in 2022 was 58.2 MW[6], on Saturday, August 6 at hour-ending 18. This set a new record for its highest historical peak.

This summer's weather for Nantucket's peak was considered much hotter than average (or 'normal'). The peak weather fell in the 76th percentile of peak weather over the last 20 years. This means that 76% of summers had peak weather that was cooler and only 14% of summers had peak weather that was warmer. This year's peak is considered 6.3 MW above the peak the company would have experienced under normal weather conditions. On a weather adjusted "normal" basis this year's peak was estimated to be 51.8 MW, an increase of 1.0% compared to last year's weather-adjusted 'normal' peak.

Nantucket's summer peak load is expected to remain to be a summer peaking system through the forecast horizon. A 1.8% annual growth rate is expected for Nantucket's post-DER peak load through the year 2050. Its peak hour is expected to shift to later of the day when EV charging demand increases, and PV saving is less available. Figure 3 shows the forecasts graphically.

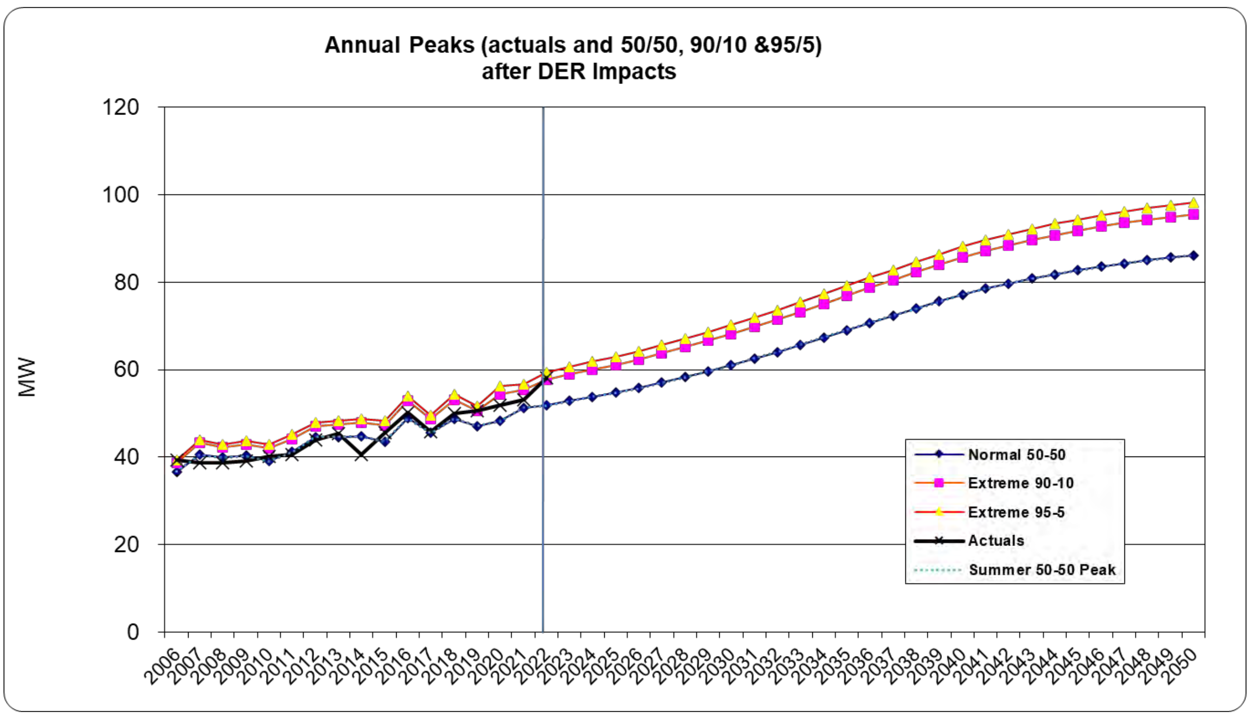

Figure 3: Nantucket Historical (actual & weather-adjusted) and Projected Peaks

6 Meter Data Service's system level PRELIMINARY and subject to change.

Forecast Methodology

National Grid in Massachusetts forecasts its peak MW demands for the two Companies and the three ISO-NE zones that make up its service territory in the state. Each Company's total as well as the "independent" (or non-coincident) peaks for each zone are developed. The independent peak is the demand that each zone experiences, regardless of whether that demand is also the same day and time as the company's peak. The two Companies and the three zonal forecasts are:

- Massachusetts Electric Company (MECO)
- Nantucket Electric Company (Nantucket)
- Northeast Massachusetts Region: comprised of the portions of the ISO-NE load zone NEMA served by MECO; includes, among others the North shore and Merrimack areas
- Southeast Massachusetts Region: comprised of the portions of the ISO-NE load zone SEMA served by MECO and Nantucket; includes, among others, the South shore, Attleboro, Uxbridge and Fall River areas as well as Nantucket Island
- West Central Massachusetts Region: comprised of the portions of the ISO-NE load zone WCMA served by the MECO; includes, among others, the Worcester, central and western areas

The overall approach to the peak forecast is to relate (or regress) peak load to aggregate system energy. For each zone, if energy alone is not a good statistical fit (because, for instance, that zone is growing more or less than the system-level energy), then other indicators such as zonal specific economics are applied. This method allows the peak MW forecasts to grow along with energy growth rates for each zone, however, it also allows the peak to adjust to individual economic influences in each zone.

Each of these models is developed based on a "reconstructed" model of past load. That is, claimed energy efficiency, installed solar PV, demand response, and energy storage impacts are added back to the historical data set before the models are run. Electric vehicle and electric heat pump impacts are removed from the historical data set. The statistical forecasts are made based on the "reconstructed" data set. Then, the future cumulative estimates of savings or additions for these DERs are taken out or added to the statistical forecasts to arrive at the final forecast. Hourly profiles for the DERs are applied to the hourly profiles for the loads to determine the annual peaks. These final loads are also referred to as "Net" loads.

The results of this forecast are used as input into various system planning studies. The forecast is presented for three weather scenarios. The transmission planning group uses the extreme 90/10 weather scenario for its planning purposes. Up until year 2019, distribution planning used the 95/5. The 50/50, or weather-normal scenario is used for various items including strategic scenarios and incentive mechanisms.

Weather Assumptions

Weather data is collected from the relevant weather stations located within the Company's New England service territory and used to weather-adjust peak demands. The relevant weather stations are Boston, Worcester, Providence, Nantucket, and Albany (due to its proximity to the western Massachusetts region). These most closely represent the Company's territory.

The weather variables used in the model include heating degree days for the colder winter months and temperature-humidity indexes (THIs)[7] for the warmer summer months. Other variables such as maximum or minimum temperature on the peak day are also evaluated. These weather variables are from the actual days that each peak occurred in each season over the historical period. Summer THI uses a weighted three-day index (WTHI)[8] to capture the effects of prolonged heat waves that drive summer peaks. Weather adjusted peaks are derived for a normal (50/50) weather scenario and extreme weather scenarios (90/10 and 95/5)[9]. A normal distribution is assumed to derive the extreme weather scenarios.

- Normal 50/50 weather is the average weather on the past 20 annual peak days.
- Extreme 90/10 weather is such that it is expected that 90% of the time it should not be exceeded. It is similarly inferred that it should occur no more than one time in a ten-year period on average.
- Extreme 95/5 weather is such that it is expected that 95% of the time it should not be exceeded. It is similarly inferred that it should occur no more than one time in a twenty-year period on average.

These "normal" and "extremes" are used to derive the weather-adjusted historical and forecasted values for each of the normal and extreme cases.

Figures 4 and 5 show the historical, weather-normal, and weather-extreme WTHI values for MECO and Nantucket, respectively.

[7] THI is calculated as (0.55 * dry bulb temperature) + (0.20 dew point) + 17.5. Maximum values for each of the 24 hours in a day are calculated and the maximum value is used in the WTHI formula.
[8] WTHI is weighted 70% day of peak, 20% one day prior and 10% two days prior.
[9] Normal distribution is assumed to derive the extreme weather scenarios. This "probabilistic" approach employs "Z-values" and standard deviations to calculate the extreme weather scenarios. As a result, the more spread out the numbers on peak days over the historical period, the more the 90/10 and 95/5 values will be above the mean (or the normal).

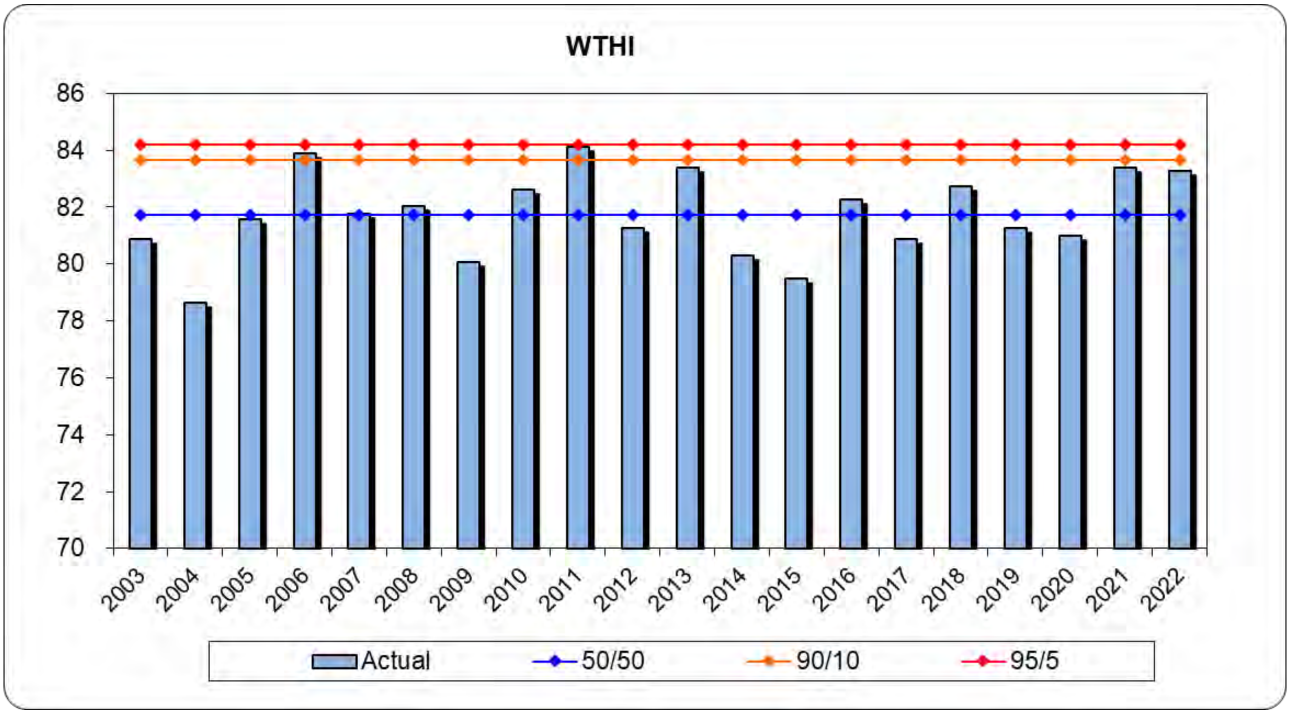

Figure 4: Actual, normal and extreme WTHI for MECO

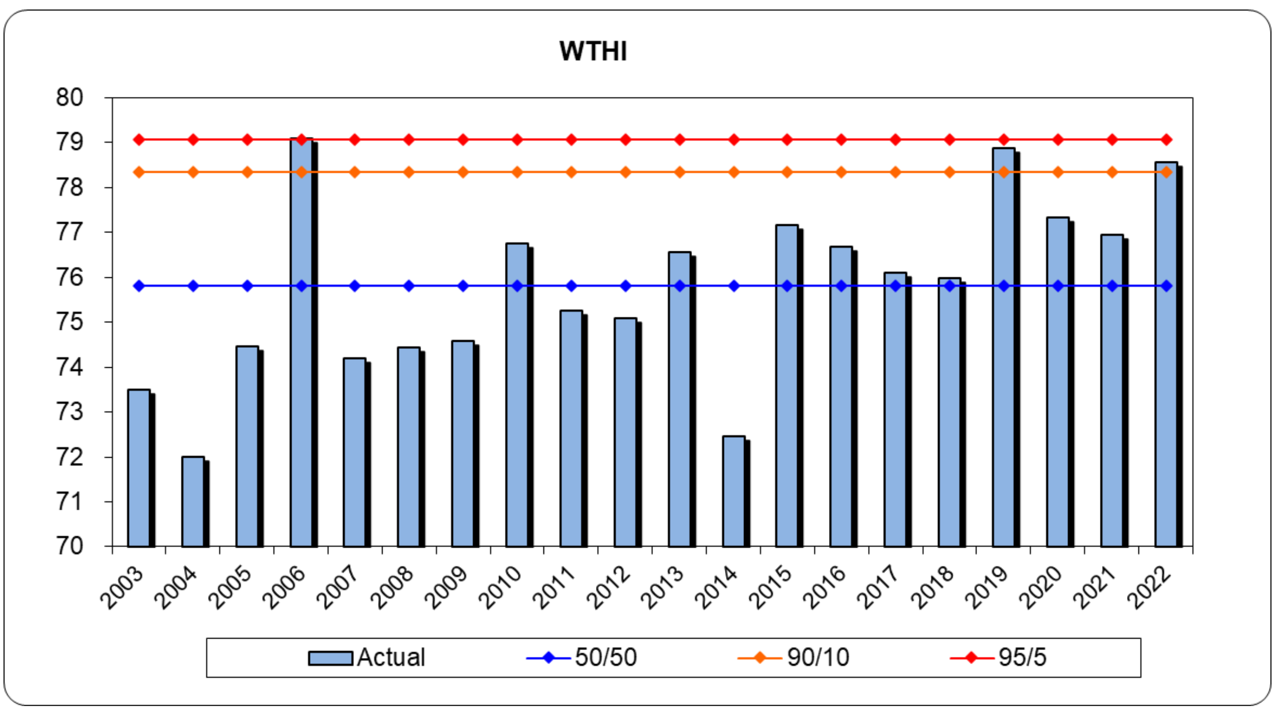

Figure 5: Actual, normal and extreme WTHI for Nantucket

Distributed Energy Resources (DERs)

In New England, there are policies, programs, and technologies that impact customer loads. These include but are not limited to energy efficiency (EE), solar photovoltaics (PV), electric vehicles (EV), demand response (DR), electric heat pumps (EH), and energy storage (ES). These collectively are termed distributed energy resources (DERs) because they impact the loads at the customer level, as opposed to traditional, centralized power supplies.

A base case forecast is developed for each of the DERs and is part of the official forecast. For each of the DERs, a higher case and a lower case than the base case are developed, as appropriate. The inclusion of multiple cases for each DER, as well as the different combinations of them, provides system and strategic planners with additional information to make informed decisions. The discussion below is based on the base case.

Figure 6 shows MECO's forecasted annual peak load. The annual peak is expected to occur in the summer between 2023 and 2035. The peak hour will shift from late afternoon to the evening hours. The reconstituted (pre-DER) load is generally lower in the evening than the afternoon, resulting in a decrease in the pre-DER load. Figure 6 shows a drop in year 2024 and year 2027 in the reconstituted load, when the peak hour shifts to later of the evening. After the DER impacts, MECO's peak is forecasted to grow, 2.2% per year on average through 2035. Starting in 2036, MECO's winter peak is expected to become the annual peak mainly driven by the increasing load from electric heating and electric vehicle charging. This shows as a step-down of pre-DER load from 2035 to 2036. However, the post-DER load is forecasted to grow through the end of the forecast horizon.

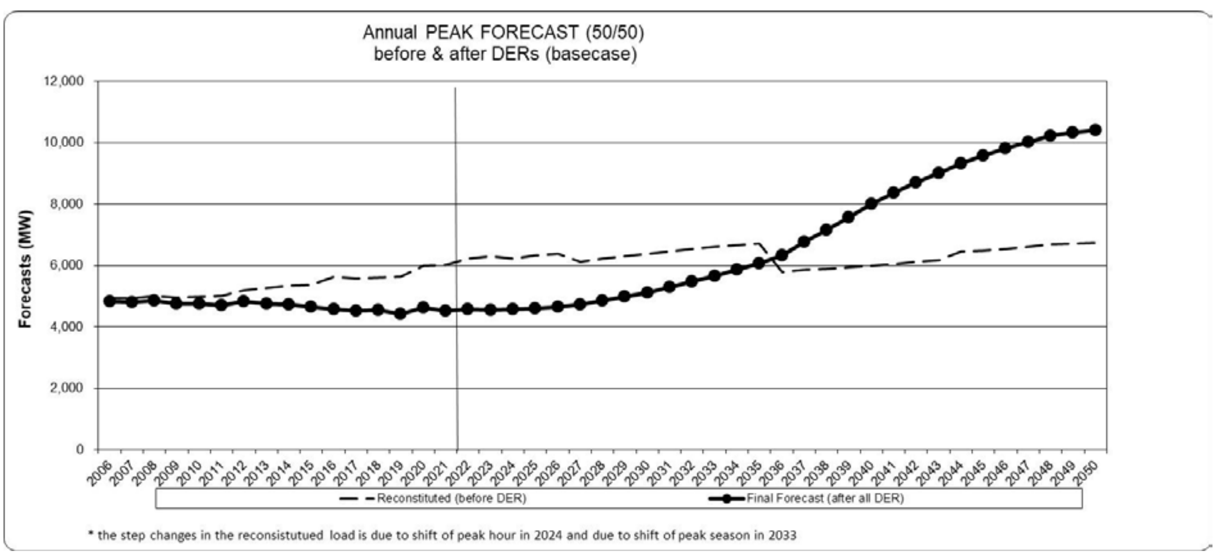

Figure 6: Annual loads before and after the impacts of DERs for MECO

Figure 7 shows the impacts for the DERs each year. The peak hour is expected to shift from hour-ending 18 to hour-ending 19 in 2024 and then to hour-ending 21 in 2027, lower or no PV impact is expected as less or no irradiation is available at this later hour. The EV and electric heat pump impacts grow faster in later years of the forecast horizon, which leads to a winter peak starting 2036 when the total net DER impacts become positive (i.e., adding load).

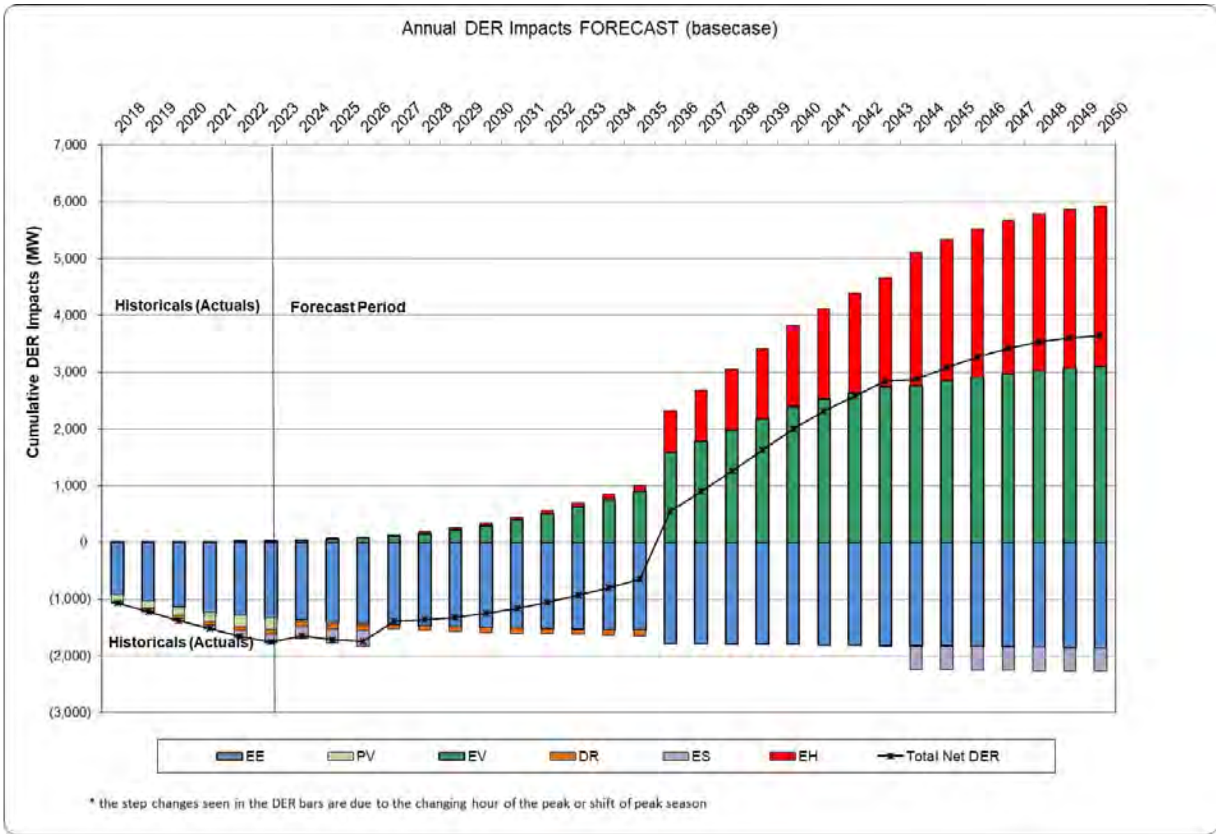

Figure 7: Annual Impact of DERs for MECO

Figure 8 shows Nantucket's expected loads and impacts for the DERs each year. The net DER impact is expected to decline with increasing adoptions of EVs and electric heat pumps.

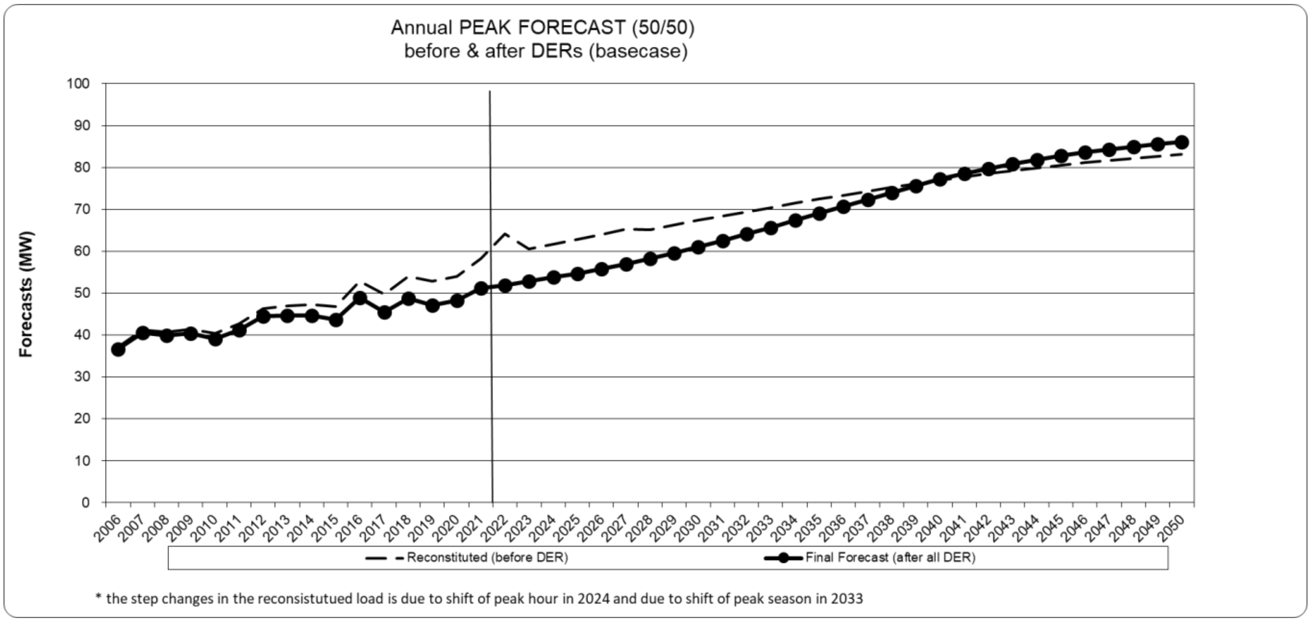

Figure 8: Annual loads before and after the impacts of DERs for Nantucket

Figure 9 shows the impacts for the DERs each year. The summer peak hour is also projected to shift to later of the day, when the PV saving is less.

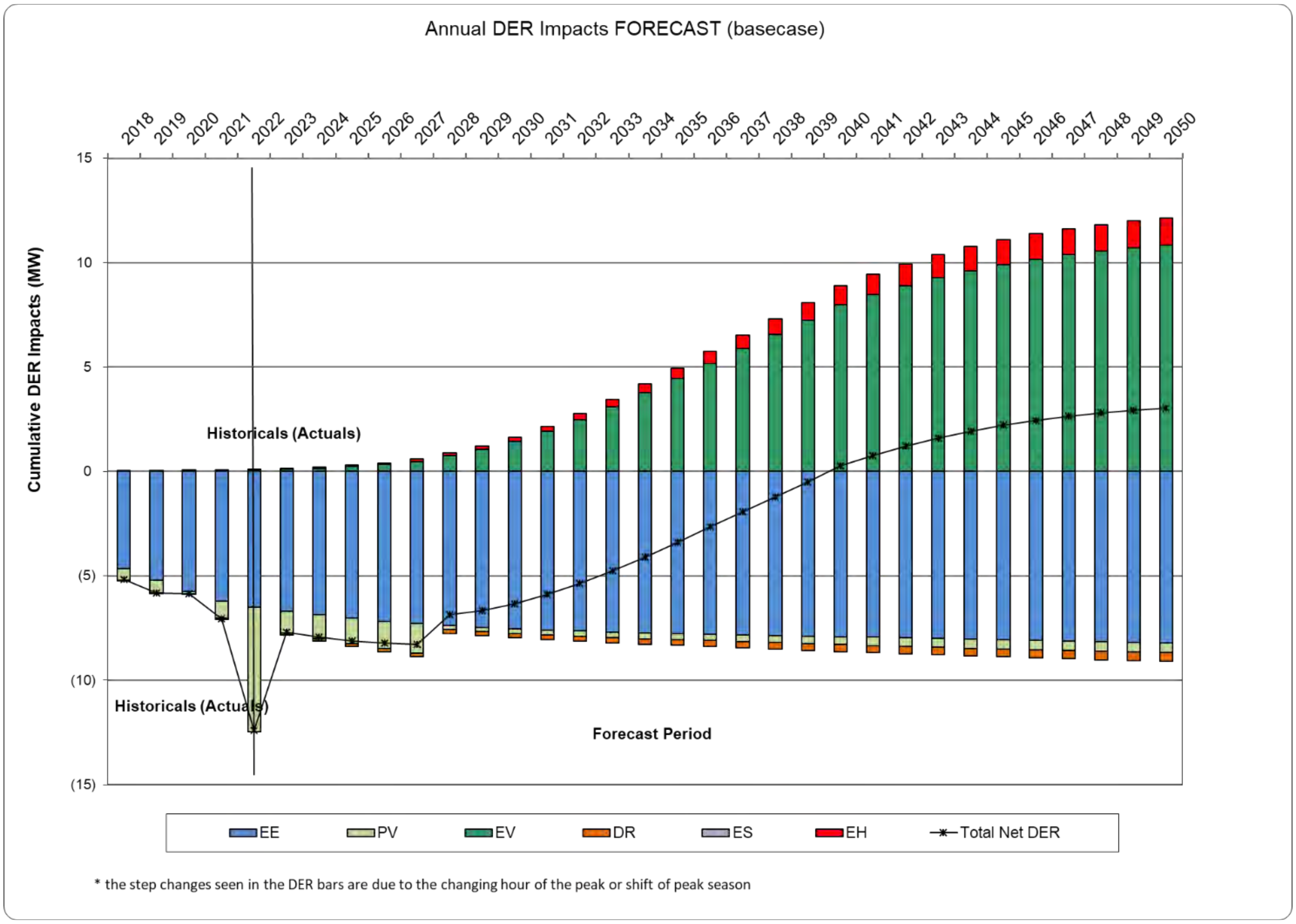

Figure 9: Annual Impact of DERs for Nantucket

Each of the DERs is discussed next.

Energy Efficiency (EE)

National Grid has had EE programs in its Massachusetts jurisdiction for many years and will continue to do so for the foreseeable future. In the short-term (one to three years), EE targets are based on Company annual plan from the Subject Matter Experts (SMEs) through 2024. Beyond 2024, the cumulative value of persistent EE savings is still expected to continue to grow but at a slower rate each year.

For MECO, as of 2022, compared to the counterfactual with no EE programs, it is estimated that these EE programs have reduced the summer peak load, which is also the annual peak load, by 1,292 MW, or 20.8% of what load would have been had these programs not been implemented. By 2050, it is expected that this reduction to the summer peak will grow to 1,633 MW or 21.1%. For winter peak load, as of 2021, it is estimated that these EE programs have reduced the winter peak load by 1,496 MW or 29.6% and are expected to grow to 1862 MW of 27.6% by 2050.

For Nantucket, as of 2022, compared to the counterfactual with no EE programs, it is estimated that these EE programs have reduced the load by 6 MW, or 11.0% of what load would have been had these programs not been implemented. The EE impacts will continue to grow to 8 MW, or 9.9% of the gross load by the year 2050.

Figure 10 &11 present the annual incremental (left-axis) and cumulative (right-axis) summer EE MW and winter EE MW for National Grid's Massachusetts jurisdiction, respectively. The value is allocated to MECO and Nantucket based on their load shares in the jurisdiction.

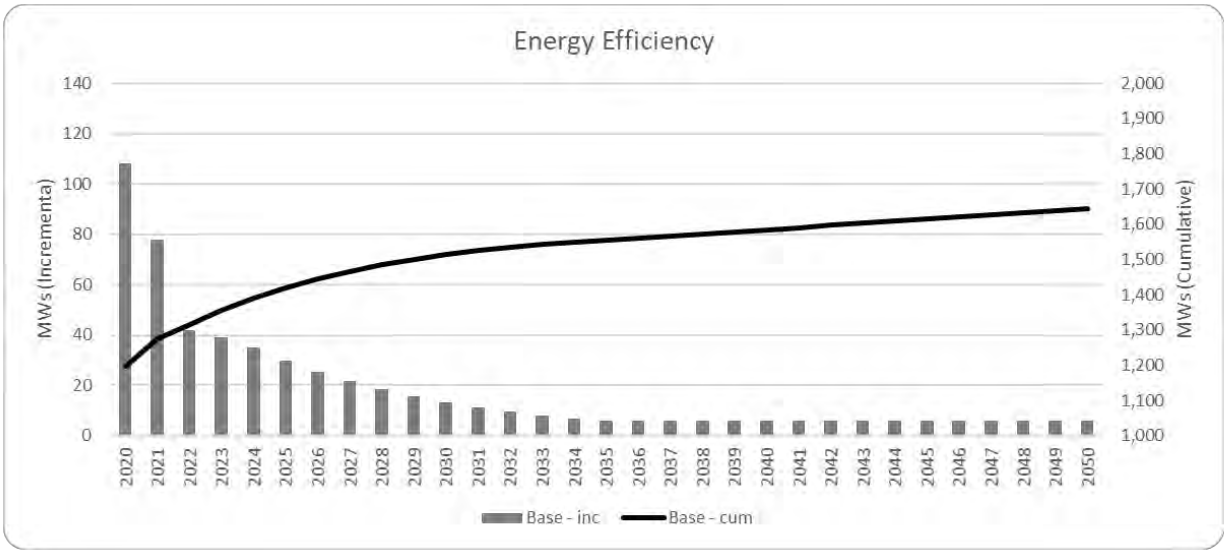

Figure 10: Energy Efficiency summer MW by year

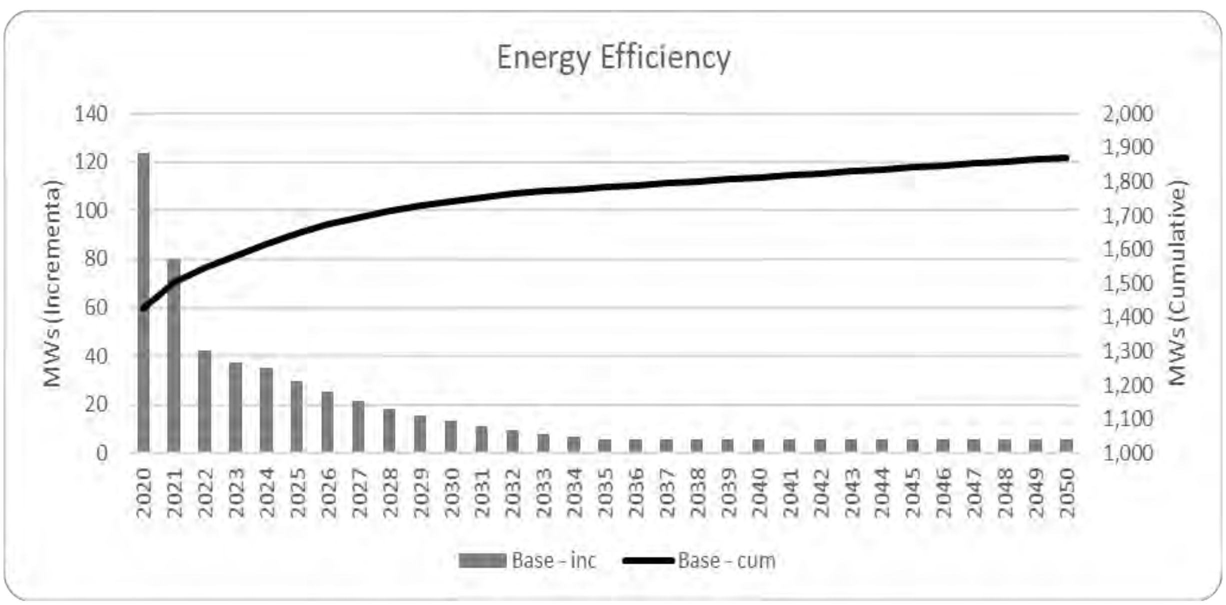

Figure 11: Energy Efficiency winter MW by year

Solar-Photovoltaic (PV)[10]

There has been a rapid increase in the adoption of PV throughout the state. The actual installed PV is tracked by the Company and used for the historical values. The near-term (2023-2027) predictions leveraged the information on the projects in the Company's queue and the insights from PV subject matter experts at the Company, and also assumes National Grid fills its share (45%[11]) of the State's existing solar standards of 3.2 GW[12] by mid 2020s. In the longer-term, continuous growth is projected in order to achieve the National Grid's share (45%) of the State policy target under the All Options scenario as stated in its 2050 decarbonization roadmap[13]. The All Options scenario targets a 6.99 GW of behind-the-meter (BTM) PV connection and a 16.2 GW of ground-mounted PV connection by 2050 for the State of Massachusetts. In this base case, it is assumed that all the BTM PV and 50% of the ground-mounted PV will be on the distribution system. It is then assumed that the Company will take its share of these. Thus, about 3.1 GW (6.9 GW * 100% * 45%) of BTM PV and 3.6 GW (16.2 GW * 50% * 45%) of ground-mounted PV are projected to be on the Company's distribution system by 2050.

Figure 12 shows the projected incremental (left-axis) and cumulative (right-axis) connected PV installations of National Grid's Massachusetts jurisdiction. The value is allocated to MECO and Nantucket based on their load shares in the jurisdiction. As of 2022, it is estimated about 1,745 MW will have been connected, growing to almost 6,716 MW by 2050.

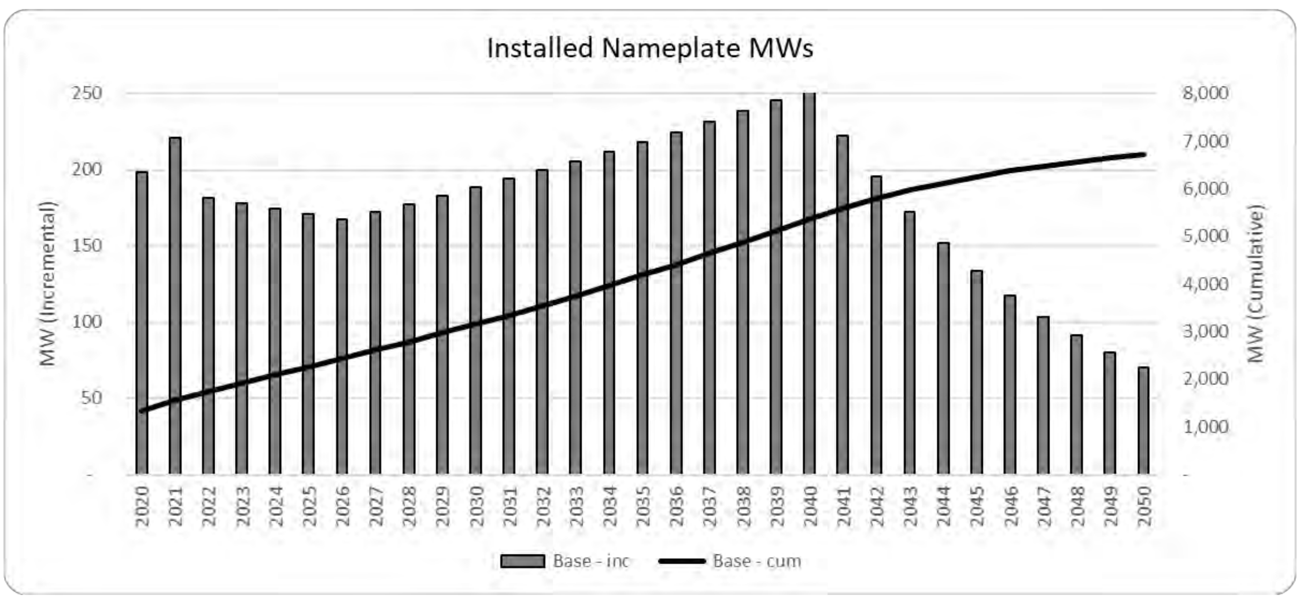

Figure 12: Solar-PV connected nameplate (AC) MW by year

While installed PV continues to grow, suppressing peak load, its impact drops off considerably as the peak hour shifts later in the day when there is less daylight. For MECO, its winter peak is expected to

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10 This discussion is limited to PV which expected to reduce loads and would not include those PV installations considered as 'supply' by the ISO-NE. This can include both 'behind-the-meter" and in "front-of-the-meter" for those installations like community solar which are allocated back to customers.

11 45% was the share for National Grid when the SMART program opened. It was the percentage of customers National Grid serves in the State of Massachusetts compared with Eversource and Unitil. This same share is assumed for calculating National Grid share of the State's existing and planned solar goals.

12 *MA Clean Energy and Climate Plan for 2030*, page 68, June 2022.

13 *Massachusetts 2050 Decarbonization Roadmap*, December 2020

exceed the summer peak and become the annual peak in later years – 2036 through 2050, PV saving is not available or much less available during the projected winter peak hour.

Electric Vehicles (EV)

EVs increase peak load over time. The EVs considered are those that plug-in to the electric system and include "plug-in hybrid electric vehicles" (PHEVs) and "plug-in battery-only electric vehicles" (BEVs). These two types are those that have impacts on the electric network. In addition to light-duty EVs that the Company has been tracking and considering in its electric load forecasts, this year, the Company expand the scope from light-duty EVs only to include light-duty, medium-duty, heavy-duty EVs and electric buses, and consider the EV adoptions of BEVs and PHEVs in these four different vehicle types.

The light-duty EV base case is developed around California's Advanced Clean Car II (ACC-II)[14] rules, which are expected to be adopted by Massachusetts. In the near-term, the zero-emission vehicle share of light-duty vehicle (LDV) sales is created based on the techno-economic potential and current market trends. In the medium-term (2026-2030), the ACC-II rules have a range of possible outcomes, so the zero-emission vehicle sales share rises in line with the "flexibilities[15]" (or lower-bound) of what the ACC-II rules require, reaching 59.5% in 2030. In the longer term (2031 and onward), zero emission vehicle sales match the ACC-II rules and reach 100% zero emissions vehicles in 2035 (and assume no more than 20% plug-in hybrid electric vehicles). Vehicle scrap is assumed based upon market data to develop the net EV in-operation numbers. The adoptions of medium-duty EV (MDEV) and heavy-duty EV (HDEV) and E-buses are based on the California's Advanced Clean Trucks (ACT)[16] rules through 2035 which have been adopted by the state. In the base case, the sales shares for MDEV, HDEV, and E-buses are estimated to be about 63%, 40%, and 75% of MDV, HDV, and buses, respectively, by the end of 2035. To extend the forecast until 2050, a similar growth rate is considered from 2036 to 2040, and after that 3% growth in sales share is assumed through 2050. That leads to 100%, 80%, and 100% sales shares for MDEV, HDEV, and E-Buses by the end of the forecast horizon, respectively.

Figure 13 shows the historical and estimated number of EVs in the National Grid's Massachusetts jurisdiction. As of the end of 2022, it is estimated that about 32,000 EVs, including light-duty, medium-duty, heavy-duty and buses, will be on the roads in MECO's service territory, growing to about 2,655,000 by the end of the forecast horizon.

[14] https://ww2.arb.ca.gov/rulemaking/2022/advanced-clean-cars-ii, retrieved September 2022

[15] Flexibilities include provisions to transfer ZEV "sales values" across all states that have adopted the regulations (e.g., a manufacturer can overachieve in California and underachieve elsewhere), provisions to sell affordable EVs in environmental justice areas, and using historical ZEV sales credits to meet the annual ZEV sales targets. All of the flexibilities provided in the rules expire by or before 2031.

[16] https://ww2.arb.ca.gov/our-work/programs/advanced-clean-trucks, retrieved September 2022

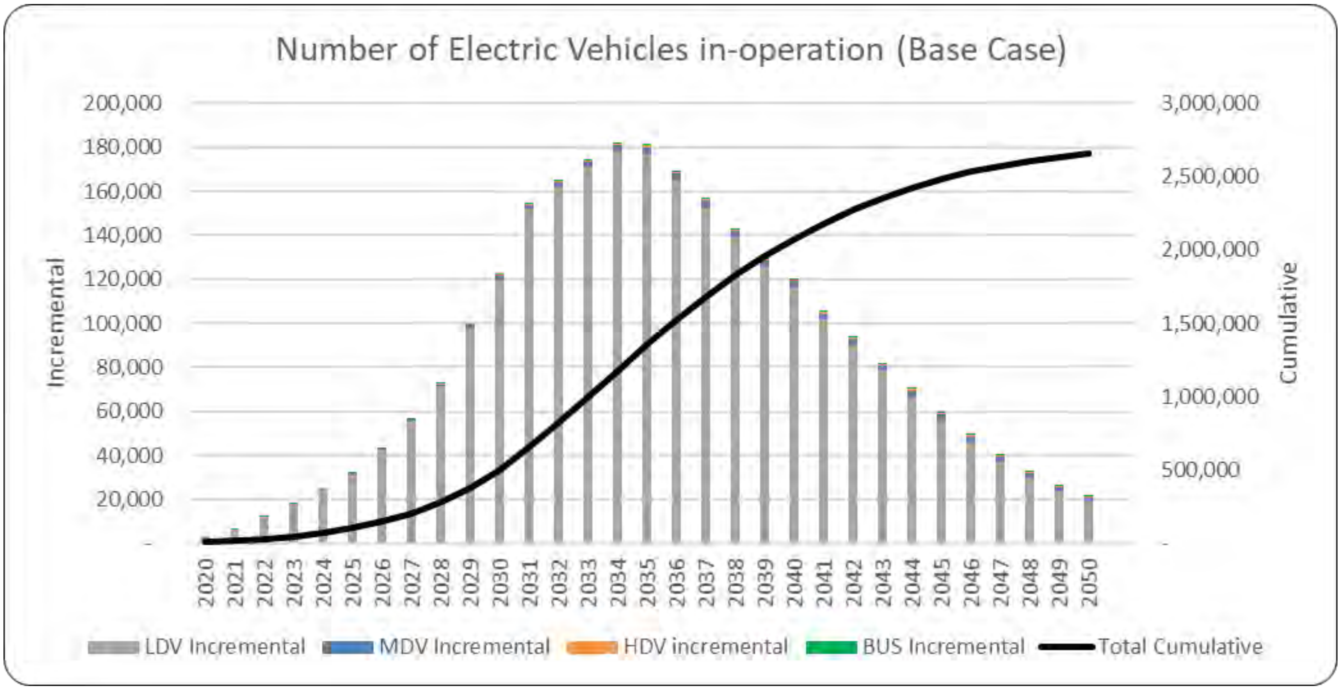


Figure 13: Number of Incremental and Cumulative EVs in National Grid's Massachusetts Service Territory

EV charging impacts are estimated for light-duty, medium-duty, heavy-duty, and electric buses separately, and vary by different season of the year too. In general, EV charging load is higher during cold weather seasons. Managed charging is not considered yet in base EV case but a managed charging scenario is provided in the low EV case to offer a view on how managed charging may impact the load. It is estimated that these electric vehicles may have increased MECO's cumulative summer peak loads by about 11.8 MW as of 2022, increasing to about 2,176 MW of cumulative summer peak load increase in the year 2050. For winter peak loads, its impact is estimated to be 11.1 MW as of 2021, increasing to about 3,099 of cumulative winter peak load increase in the year 2050. For Nantucket, the increase of summer peak load is negligible as of 2022 but is expected to grow to 10.9 MW by 2050. While EVs do add to both peak and energy loads over time, they are considered 'beneficial'[17] electrification.

Electric Heat Pumps (EH)

The base case is based on the Company's heat pump targets through 2024. Post 2024, the Company assumes that Company's pro rata shares of CECP phased pathway's target in 2050[18] will be met. Thus, about 1.34 million of units will be installed by 2050 and about 80% of those will be installed as full applications. A full application is defined as a heat pump unit that will serve the all the heating and cooling in the home or building. A partial heat pump is defined as a unit that will supplement existing heating system, as well as cool the home or building during the summer season. Penetration rates are expected to be about 86% of residential homes and 58% of commercial space heating capacity by 2050.

[17] Beneficial electrification is based on an overall portfolio of lowered carbon emissions from the transportation sector coupled with lower/carbon free generation of electricity in the power sector to support the charging of the EVs.
[18] *Massachusetts Clean Energy and Climate Plan for 2025 and 2030*, June 2022

Figure 14 shows the projected heat pump adoptions through the forecast horizon.

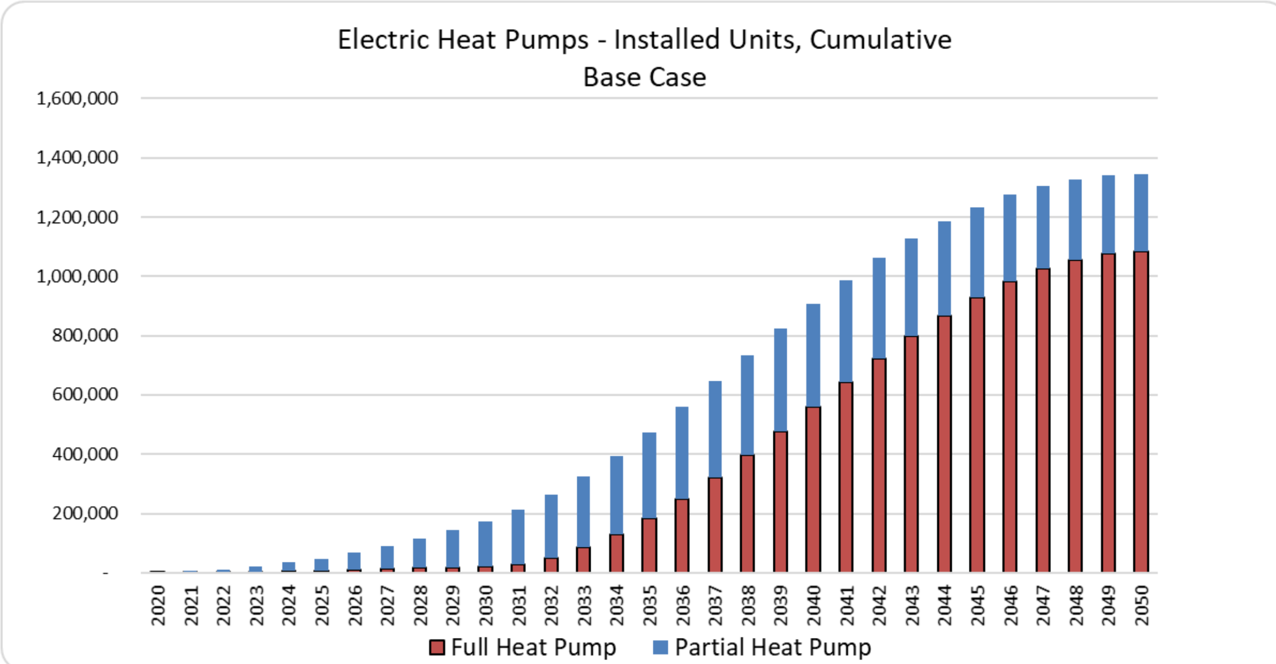


Figure 14: Cumulative Number of Electric Heat Pumps

<u>Demand Response (DR)</u>

DR programs actively target reductions to peak demand during hours of high expected demand and/or reliability problems. These resources must be dispatched, unlike the more passive energy efficiency programs that provide savings throughout the year. The DR programs enable utilities and operating areas, such as the New England Independent System Operator (ISO-NE) to act in response to a system reliability concern or economic (pricing) signal. During these events, customers can actively participate by either cutting their load or by turning on a generator to displace load from behind the customer's meter.

In general, there are two categories of Demand Response programs in Massachusetts. These are ISO-NE programs and Company retail level programs.

The ISO-NE programs, referred here as "wholesale DR", have been active for several years and were periodically activated. There were no ISO-NE DR events this year, and there has not been one since 2016. The company's policy has been to add-back reductions from these DR events to its reported system peak numbers. This is because the Company is not in control of the dispatch days or times and thus there is no guarantee that these ISO-NE events would be at the times of company peaks. Therefore, the Company must plan to assume they are not dispatched.

The Company recently began to run its own DR program at the retail customer level. In contrast to the wholesale level DR programs implemented by the ISO-NE, these programs are activated by the Company. The company counts the impact of DR resources enrolled in the retail program as load reductions.

In 2022, for MECO, the estimated impact on summer peak was 101 MW (in the retail program only) and is expected to grow to about 222 MW the year 2050. The hours of dispatch for DR are assumed to move over time to capture the hours of the peak, however, as the hours of the peak move outside of normal commercial sector activity, it is expected that DR impacts would be harder or impossible to achieve during peak hour(s). No DR program is expected for winter at this point.

Energy Storage (ES)

For the base case targets, it is assumed that the Company would make a share of the statewide energy storage policy goals. In Massachusetts, the state policy is 1000 MWh by 2025[19]. For summer peak impacts this is first converted to a MW equivalent using a four to one charging to peak output factor. Thus, the 1000 MWh target is about 250 MW. Only a portion of these is at the distribution level and will lower the load forecast (the remainder being considered supply by the ISO-NE and not considered in this load forecast). Based on the amount of energy storage installed in the state as of 2021, about 37% is considered distribution level and thus load reducing. Based on this the storage targets considered load reducing are lowered to 92.5 MWs (37% * 250) by year 2025. The Company's share of storage as in the state as of this year is about 78%. This is assumed to persist through year 2025. Thus, it is assumed that the year 2025 target for the Company is 72.15 MW (78% * 150). Not all energy storage will help to reduce the Company's summer peaks. A number of customers may use their storage to serve their own needs and times. It is assumed that only 85% of the installed energy storage amounts will impact the peak load. Thus, the final year 2025 target for peak reducing storage is 61.3 MW (85% * 102).

Massachusetts does not currently have explicit energy storage targets beyond year 2025. However, the State has published two studies, one the Clean Energy and Climate Plan for 2030 (CECP) and two the "Energy Pathways to Deep Decarbonization 2050". In the 2050 document, there are several scenarios that can guide the state to meeting its year 2050 long-term Climate goals. For example, by the year 2050, the "All options" scenario implies about 3,000 MW of large-scale energy storage (generation), "100% Renewable" scenario implies about 4,000 MW and the "No thermal" scenario implies 12,000 MW[20]. The Company used those inferred long-run energy storage capacity to provide a context to its long-term forecast at the distribution level. In order to do that, the company made two assumptions in the long run: (a) the company 'share of energy storage in the state will approximate the company's load share in the state (45%) and (b) more energy storage will move towards the supply side and less new storage as distribution level load reductions. The longer-term distribution share is assumed to drop to 20% (vs. 37% now). By using these assumptions, the current company's long term energy storage installed capacity forecast in 2050 will relate to the different pathways from "Energy Pathways to Deep Decarbonization 2050 as follows: the base case forecast of 516 MW will be between "All Options" and "100% renewable" scenarios. Finally, it is assumed the long-term peak reducing estimate will remain at 85% (85% is based on similar findings in New York which have significant pricing signals during peak hours). For the base case scenario, this lowers the final target to 439 MW by year 2050 (85% * 516).

The actual projections for installed energy storage are as follows. As of the end of year 2021 there was about 111 MW installed in the Company's service territory, about 58 MW of which was installed in

[19] https://www.mass.gov/info-details/esi-goals-storage-target, retrieved November 2022

[20] *Energy Pathways to Deep Decarbonization. A Technical Report of the Massachusetts 2050 Decarbonization RoadMap*, page 61, December 2020

the year 2021 alone. The base case assumes a continuation of this 58 MW per for the next three years, before assuming some saturation. Saturation is assumed to be 20% less per year for each subsequent year forward. This puts the Company on a path to easily surpass both the year 2025 and year 2050 targets determined above. Thus, it can be said that the Company is on-target for the CECP 2030 goals for this DER.

All prior discussion on load & DERs above is limited to the base case. Additional higher and lower scenarios are provided later in this section (see 'DER scenarios') and in the Appendices.

Peak Day 24 Hourly Curves

While the single peak values discussed so far are of major importance, the estimated impacts due to DERs on an hourly basis on these peak days is also important. For the two companies and for each of the zones, a 24-hour peak day load profile is provided. This allows the companies to look beyond the traditional approach of predicting only the 'single' highest seasonal system peak each year. The process now looks at the hourly load shape of all 24 hours of each peak day for each year of the planning horizon to determine the load and impact of DERs. This is useful to show the changing hours of the peaks as more DERs are added. For example, as more and more solar PV is placed on the system, the concept is that the summer peak hour will shift away from afternoon hours where solar irradiation is highest to evening hours as the solar reductions taper off. And as more electric vehicles chargers are installed, evening and nighttime loads can go up.

Figure 16 shows the "24 hour" peak summer day for selected years over the planning horizon for the base case DERs for MECO. "Gross" refers to loads before DER impacts and "Net' refers to loads after DER. The selected years are 2022, 2027, 2032, 2040, and 2050. The figure clearly shows how the expected DERs lower the load during middle of the day and add load from electrifications, which leads to the shift of the peak hour from afternoon to evening and night. Figure 17 shows the impact of the "24 hour" peak summer day under the DER scenario of managed light-duty electric vehicle charging and base cases for all other DER technologies. Under this scenario, the EV charging load is shifted from traditional peak hours of afternoon and early evening to late of the night, and the magnitude of the peak load is also lower than the scenario that EV charging is unmanaged.

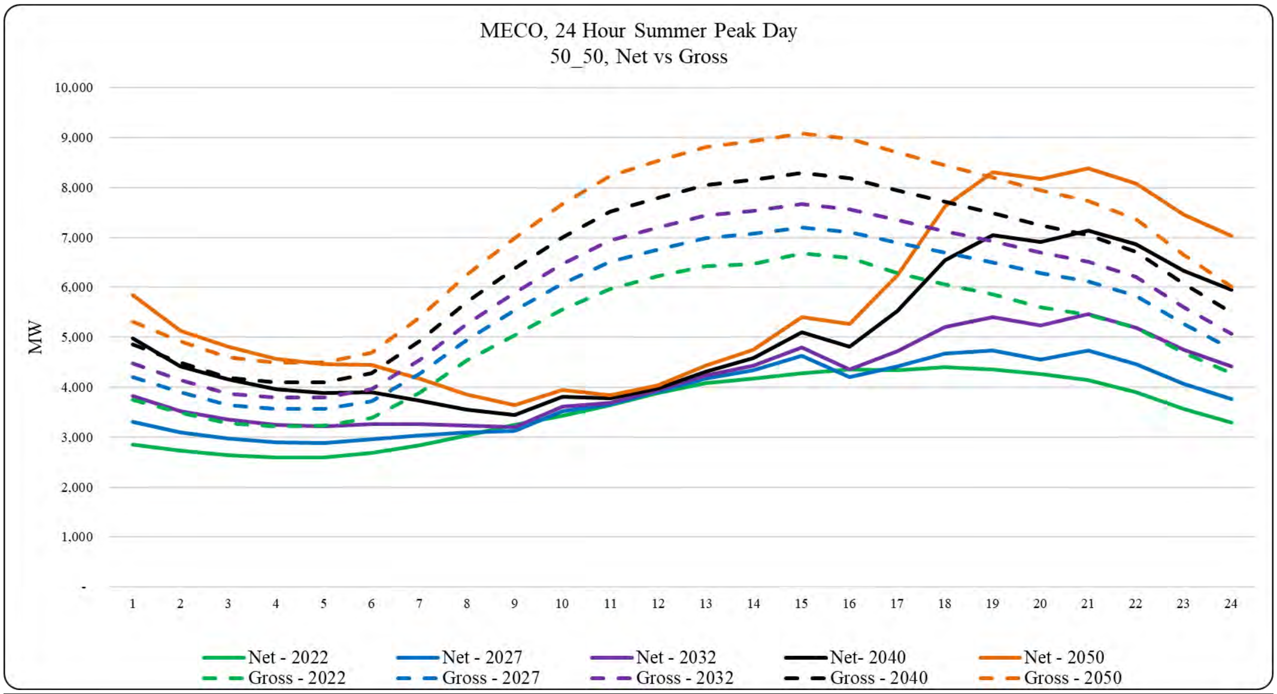


Figure 16: Peak Summer day hourly load, pre and post DERs for MECO

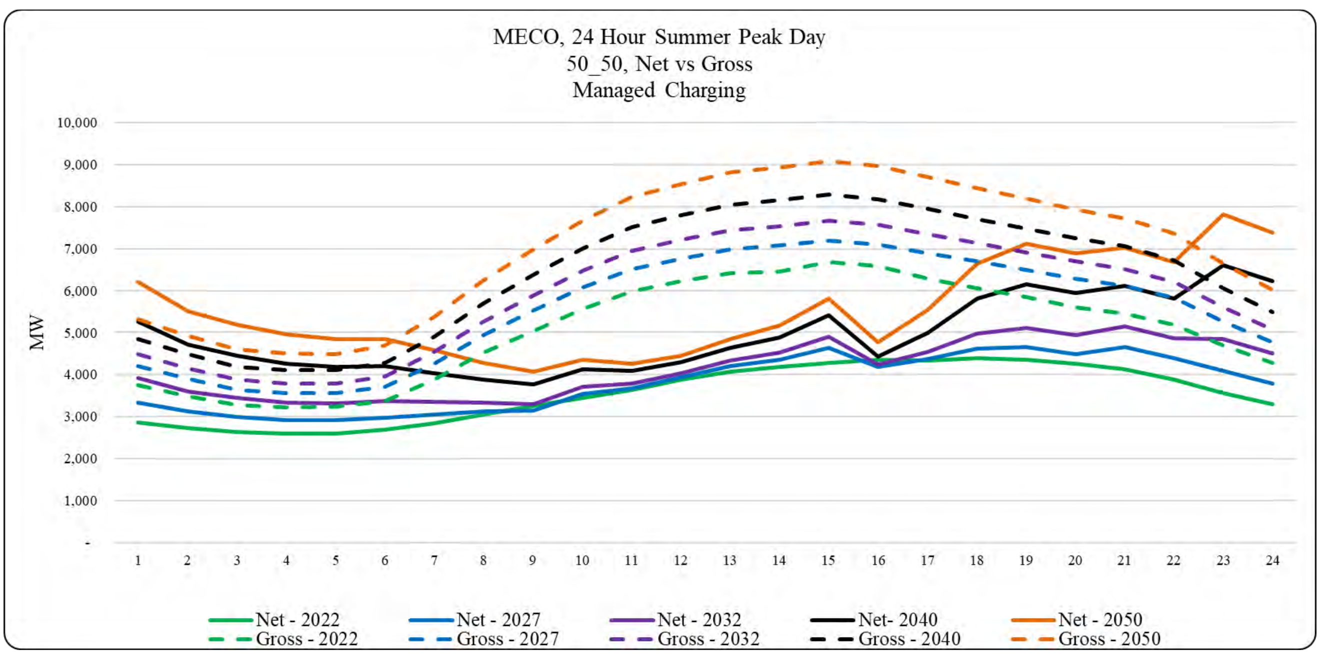


Figure 17: Peak Summer day hourly load, pre and post DERs for MECO under managed light-duty electric vehicle charging scenario

Figure 18 shows the "24 hour" peak winter day for selected years over the planning horizon with the base case DERs. The selected years are 2021, 2026, 2031, 2040 and 2050. The figure shows the dual peaks associated with winter days. The morning and evening/night load quicky ramp-up from the demand of EV charging, and electric heating, as well as the savings from PV becoming less available or unavailable during peak hours. Figure 19 shows the impact of the "24 hour" peak winter day under the DER scenario of managed light-duty electric vehicle charging and base cases for all other DER technologies. Under this scenario, the EV charging load is shifted from traditional peak hours of early evening to late of the night, and the magnitude of the peak load is also lower than the scenario that EV charging is unmanaged. The load of other hours are pushed higher with charging load being shifted to those hours.

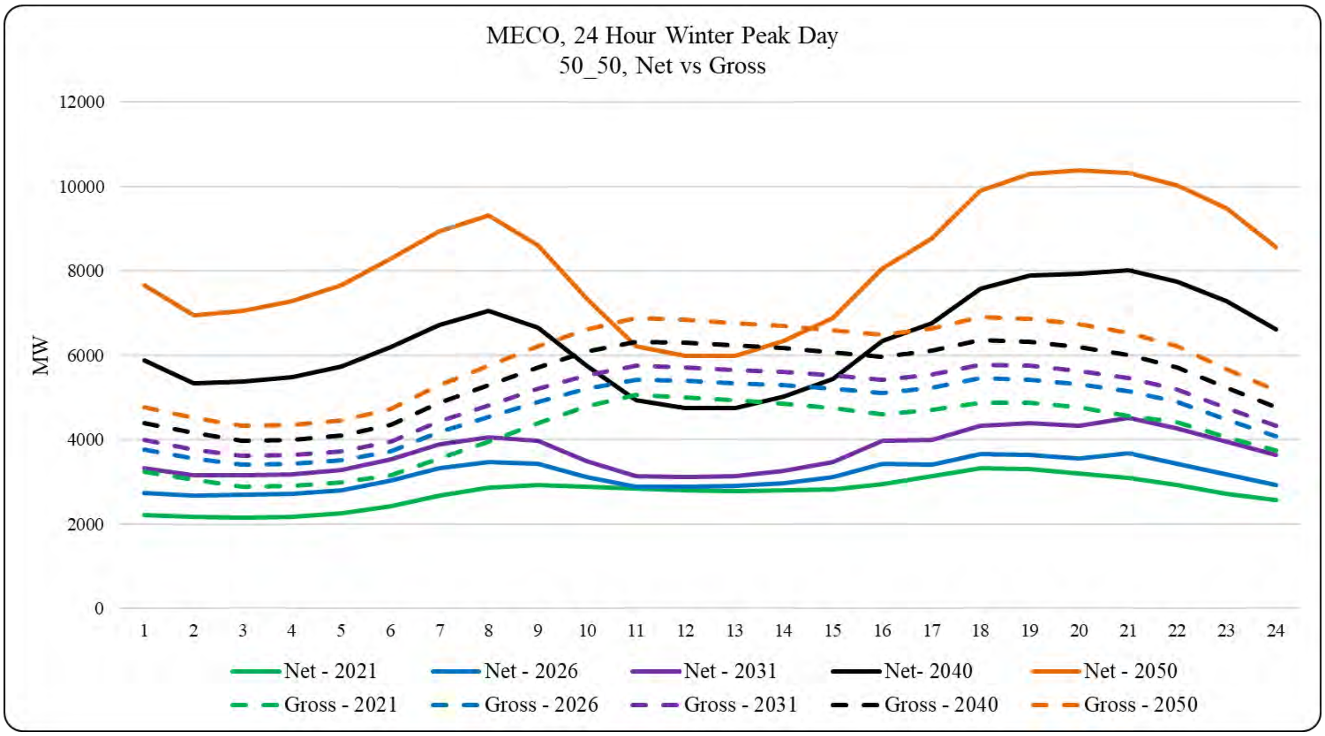


Figure 18: Peak Winter day hourly load, pre and post DERs for MECO

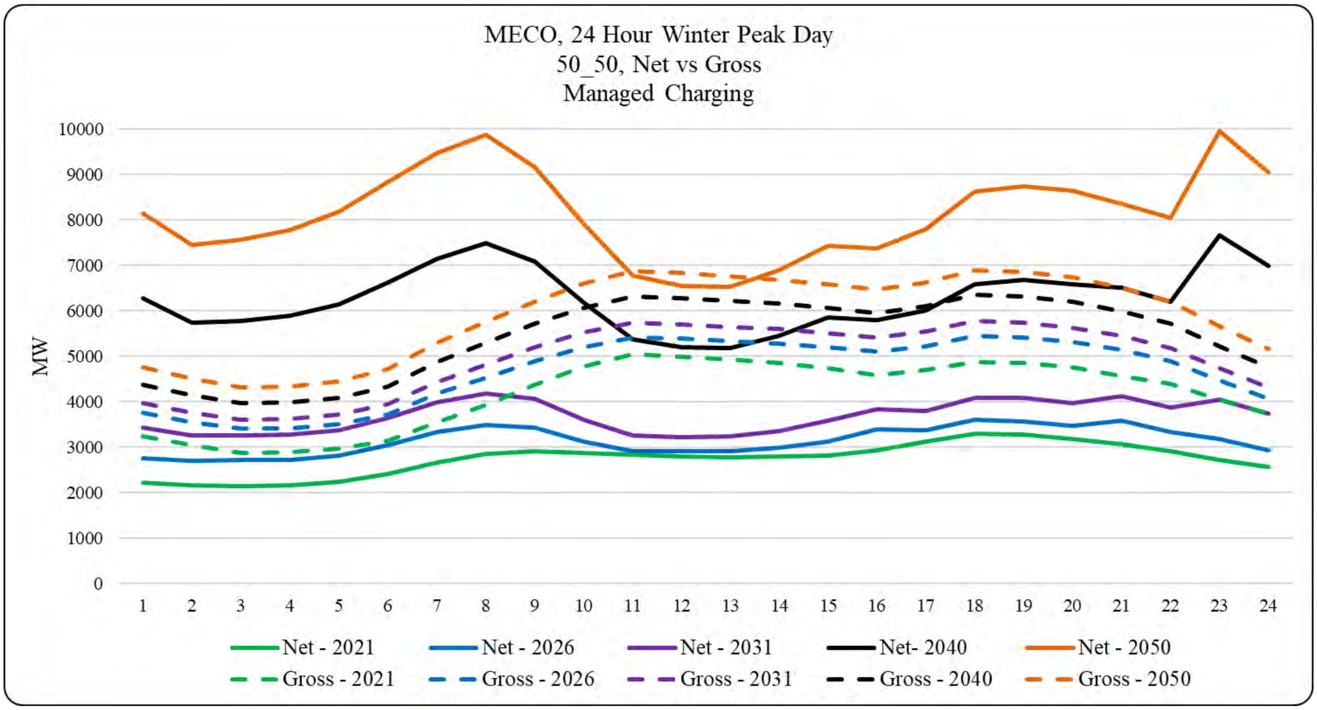


Figure 19: Peak Winter day hourly load, pre and post DERs for MECO under managed light-duty electric vehicle charging scenario

Appendix E contains additional load shapes for other day types including summer, winter and shoulder month average weekdays and weekends. These show the varying seasonal patterns as well as the lower load shoulder months which are mostly comprised of base load with minimal impacts of cooling or heating. Weekend load patterns also provide insight to lower load profiles since there is no weekday business load.

DER Scenarios

The body of this report thus far has shown results for the peak forecast with the base case DERs scenario. The Company has also looked at a number of scenarios where each of the DERs (EE, PV, EV, DR, ES, EH) also has a higher-case and a lower-case scenario, as appropriate. Looking at a range of scenarios can provide planners with additional information on what loads might be under various combinations of DER scenarios[21].

Each of the various combinations of DERs scenarios – base, high and low – were modeled. This creates thousands of combinations. In order to assess the probabilities of any one of these scenarios occurring, each DER technology was assigned a 'probability' level. For example, for the three EE cases, these were assigned 60% likelihood for the base case, 5% for the high case and 35% for the low case. These assignments are based on group consensus with the SMEs for the DER and sum to 100%. This process is repeated for each DER. Table 1 shows the probabilities used in the forecast.

Table 1: Probabilities for each DER case

MA	Low	Base	High
Energy Efficiency	35%	60%	5%
Solar - PV	20%	75%	5%
Electric Vehicles	15%	70%	15%
Demand Response	5%	85%	10%
Energy Storage	10%	80%	10%
Electric Heat Pumps	20%	75%	5%

Figure 20 & 21 shows summer and winter net load under selected DER scenarios – base case (which is the most likely) is blue solid line and the maximum and minimum cases are red solid lines which provide the highest and lowest bounds for planning purposes The base is the scenario with base cases from all DER technologies. The maximum load scenario / minimum DER saving scenario is the scenario with high cases for energy efficiency, solar PV, demand response, and energy storage; and low cases for electric vehicles and electric heat pumps. The minimum load scenario / maximum DER saving scenario is the scenario with low cases for energy efficiency, solar PV, demand response, and energy storage; and high cases for electric vehicles and electric heat pumps. It also shows the other more likely cases besides the base case, and they are shown as black dashed lines.

[21] In this forecast, six DERs, each with three cases – base, higher and lower, creates 729 cases (3^6) for each weather scenario. With three weather scenarios 2,187 scenarios are generated for the Company and the same for each individual zone.

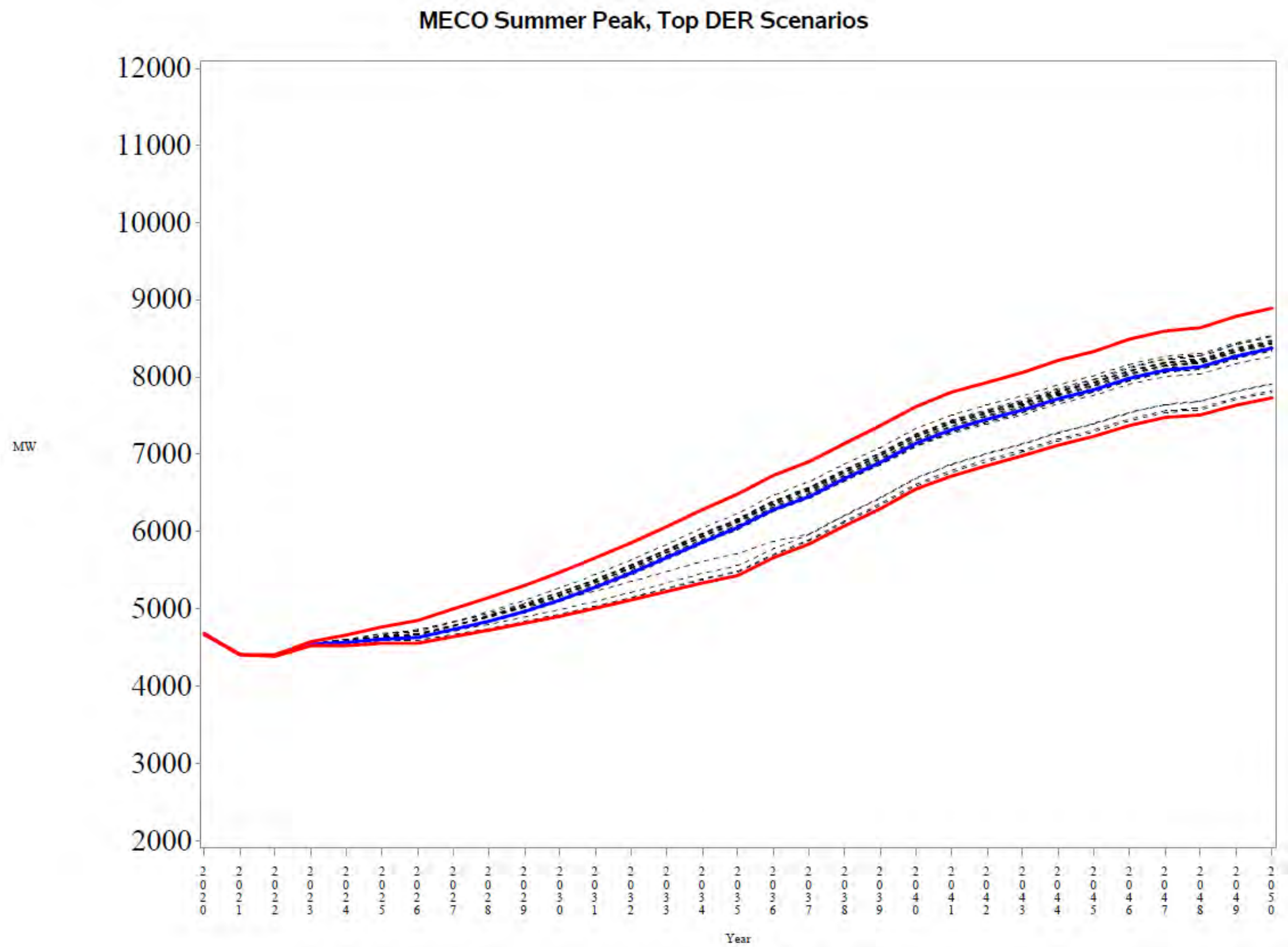


Figure 20: MECO Summer Peaks (50/50), NET, selected DER scenarios

Figure 20 shows that the summer peak load five years from now or in year 2027, ranges from about 4,641 MW to 5,004 MW - a 363 MW spread, with the base case at 4,732 MW. The uncertainty increases over time, so that by year 2050, the range expands to from about 7,732 MW to 8,891 MW, or almost a 1,158 MW spread, with the base case at 8,377 MW.

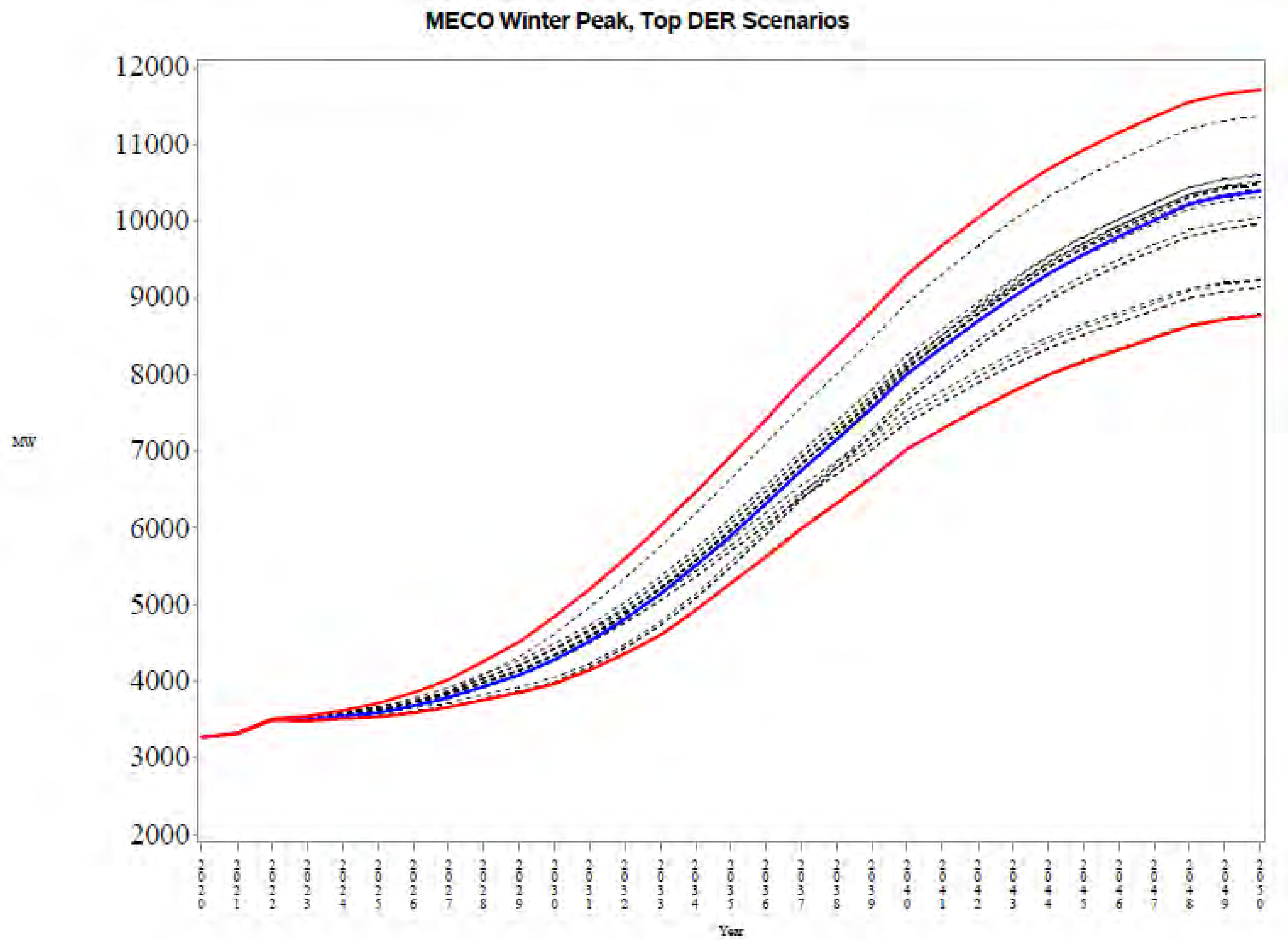


Figure 21: MECO Winter Peaks (50/50), NET, selected DER scenarios

Figure 21 shows that the winter peak load five years from the most recent winter or in year 2026, ranges from about 3,585 MW to 3,846 MW - a 261 MW spread, with the base case at 3,677 MW. The uncertainty increases over time, so that by the year 2050, the range expands to from about 8,769 MW to 11,711 MW, or almost a 2,942 MW spread, with the base case at 10,389 MW.

It is noted that while the maximum and minimum cases are shown to provide bounds for the forecast, those specific scenarios are very, very unlikely.

While Figure 20 & 21 above show what the longer-term annual summer peaks and winter peaks look like, Figures 22, 23, 24, and 25 show what the 24-hour peak day profiles might be for selected years.

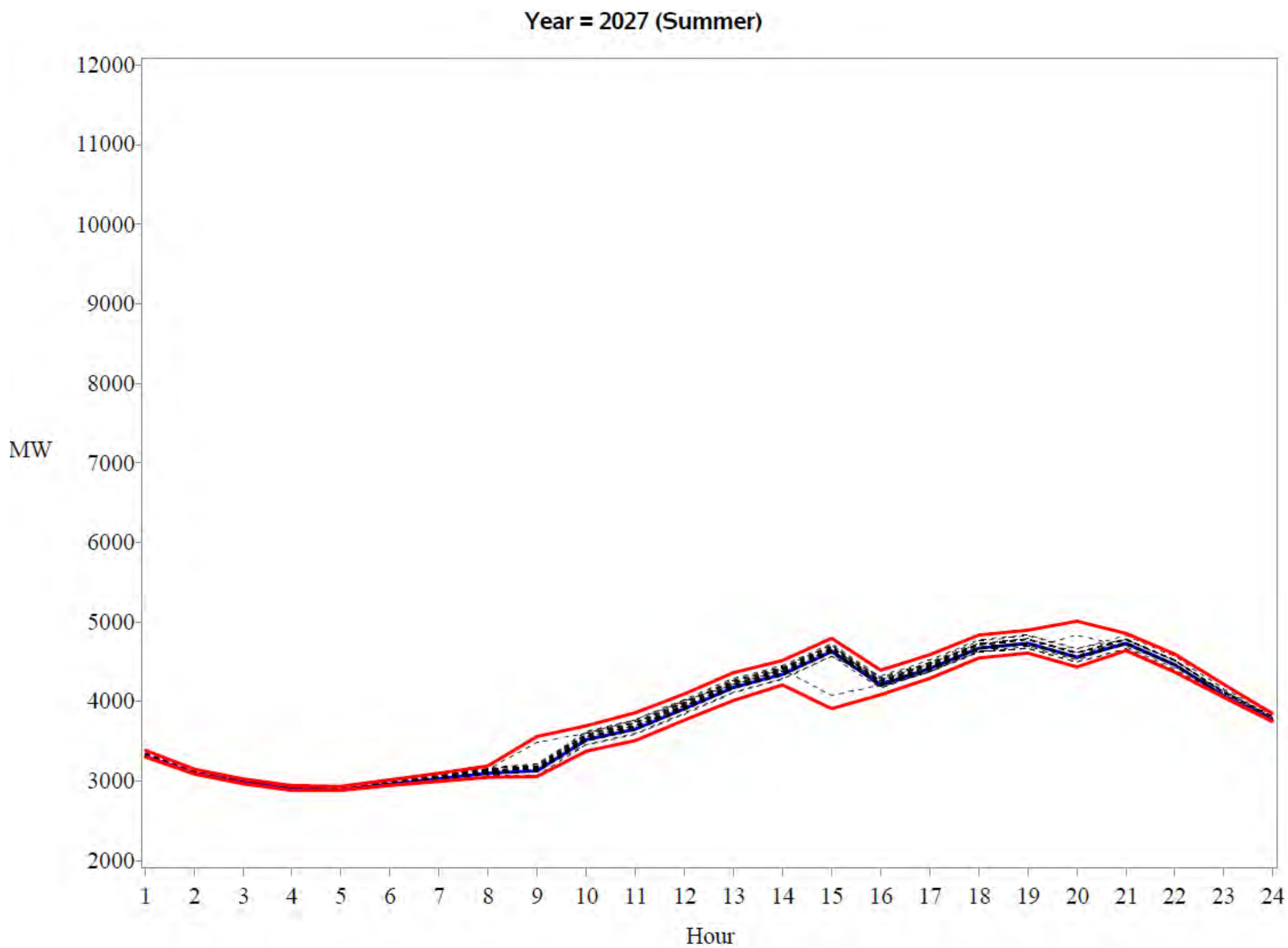


Figure 22: MECO 50/50 case, net summer peak, with range of DER scenarios, year 2027

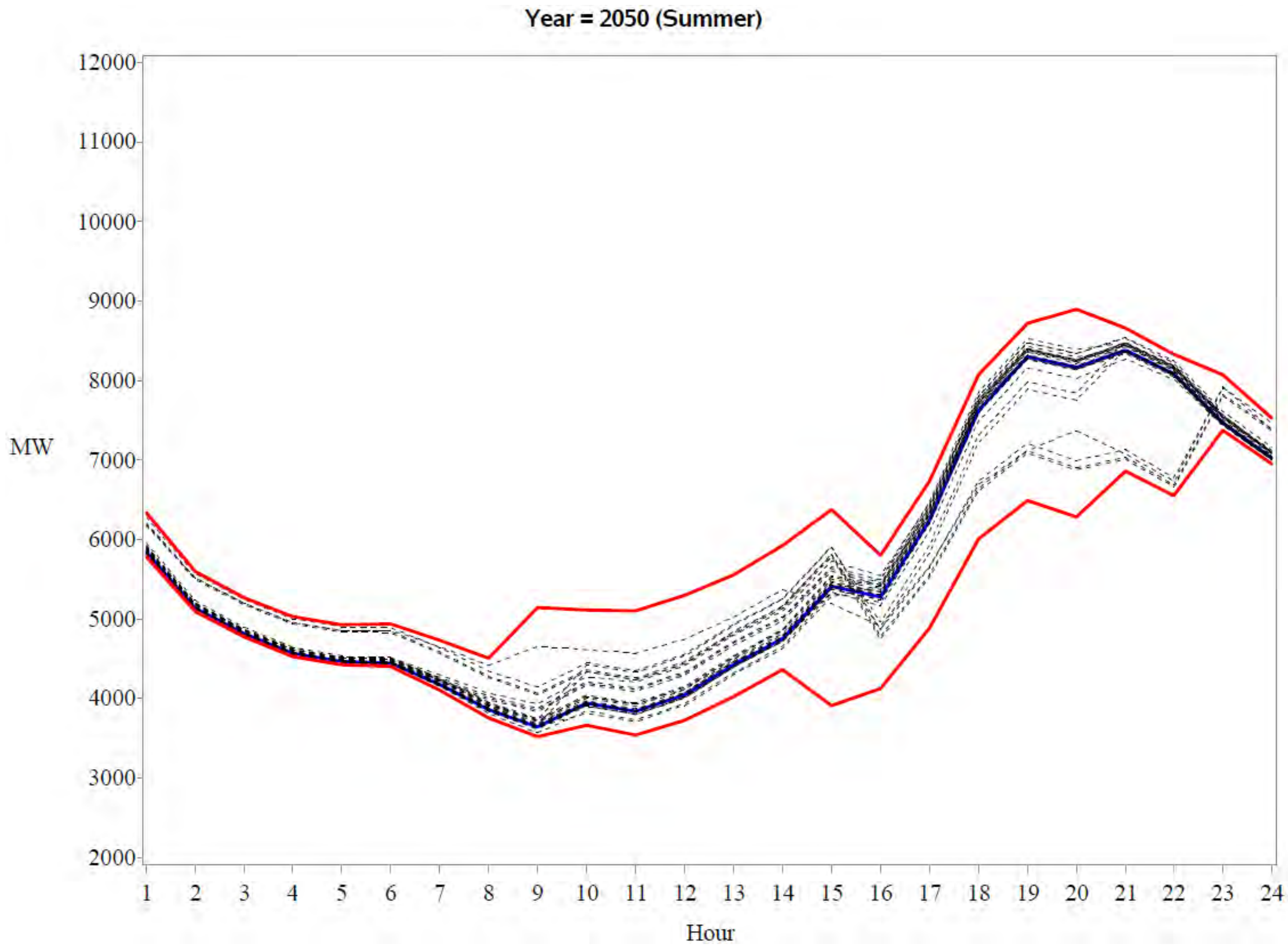


Figure 23: MECO 50/50 case, net summer peak, w/range of DER scenarios, year 2050

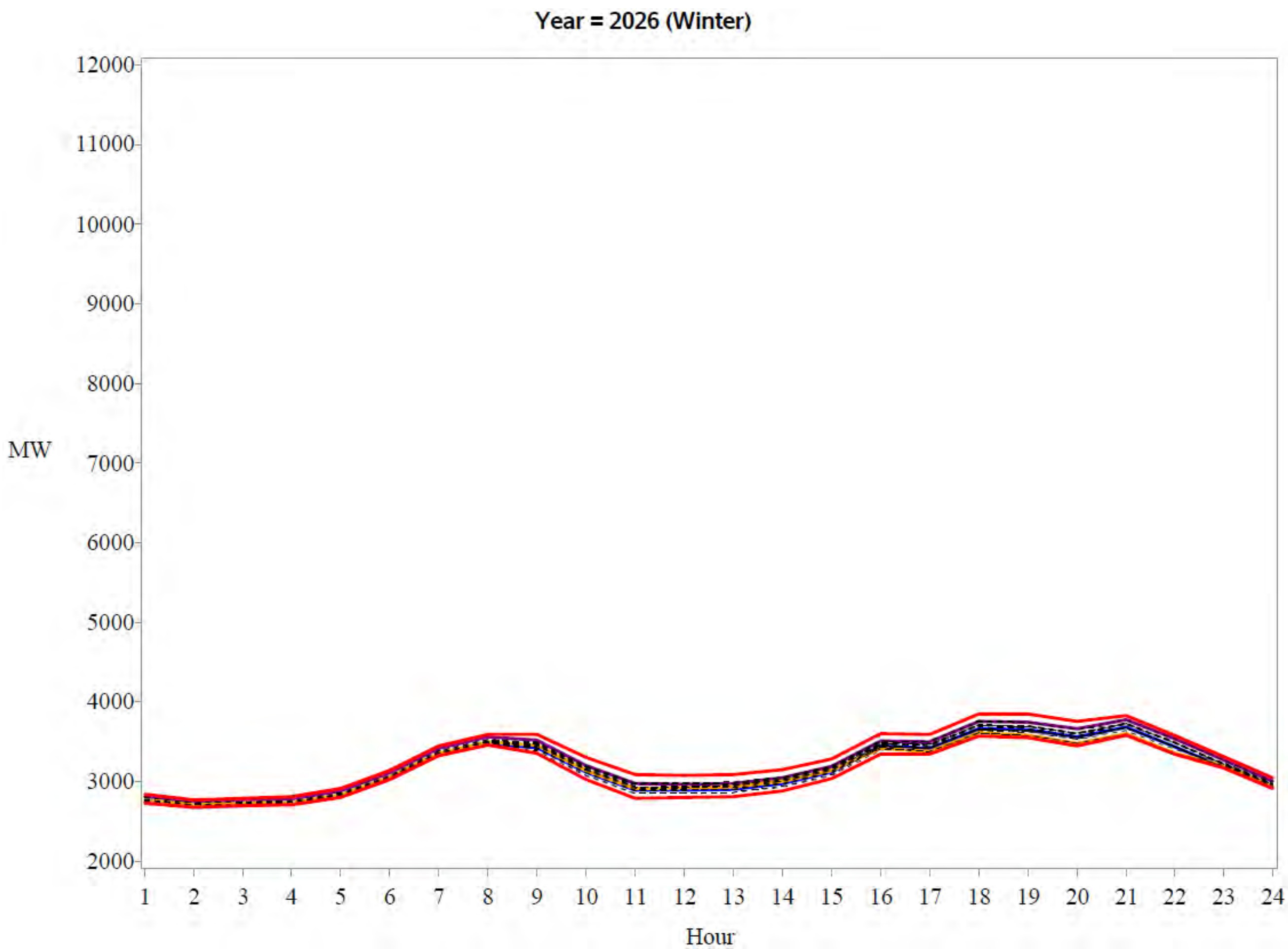


Figure 24: MECO 50/50 case, net winter peak, w/range of DER scenarios, year 2026 (blue = base; red = highest and lowest load scenarios; yellow = managed EV charging; purple = high electrification scenario)

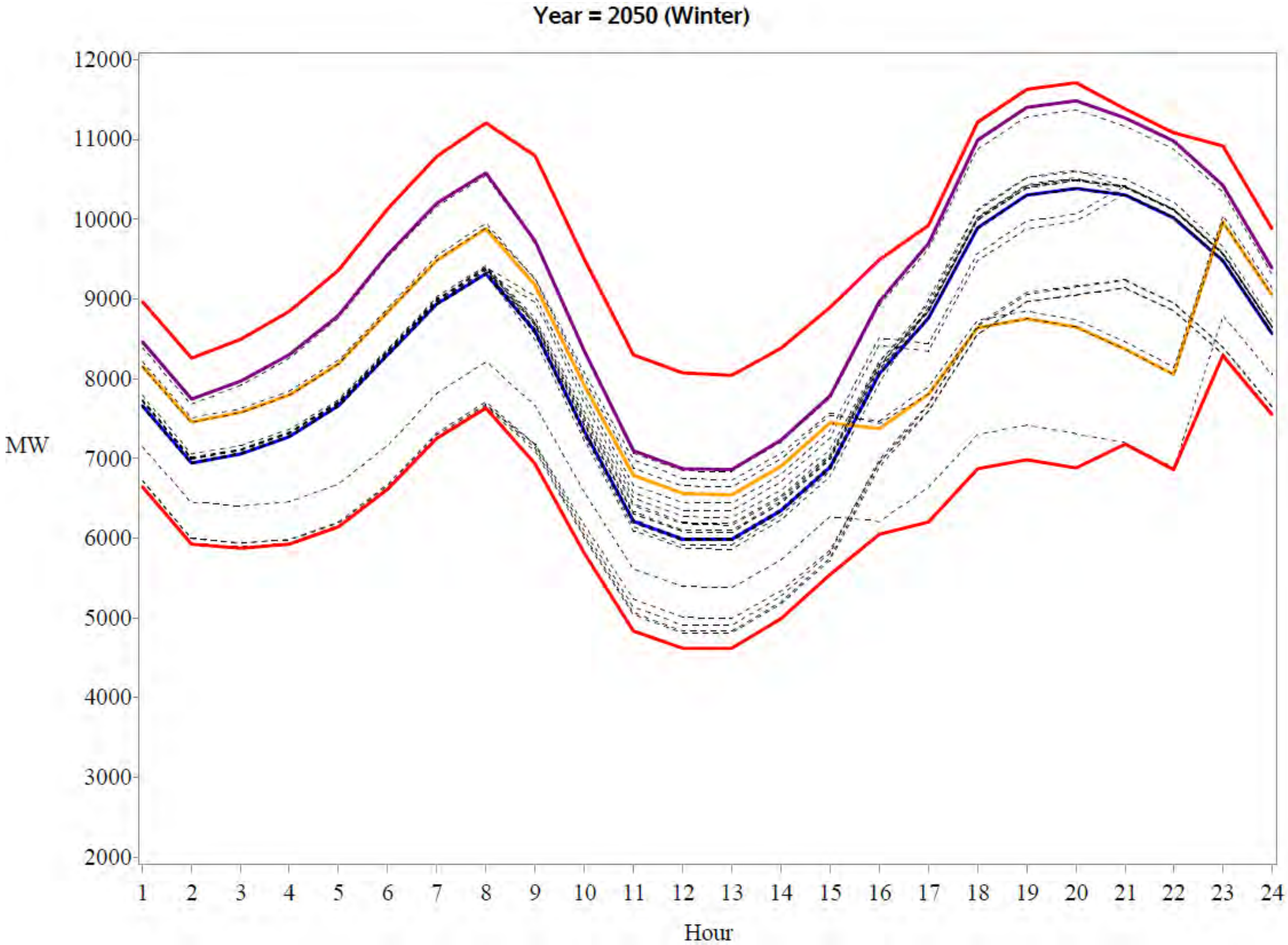


Figure 25: MECO 50/50 case, net winter peak, w/range of DER scenarios, year 2050 (blue = base; red = highest and lowest load scenarios; yellow = managed EV charging; purple = high electrification scenario)

Appendix F and G discuss the DER cases in more detail.

The base case DER projections included in this forecast are based on current trends, approved programs, existing state policy targets, and industrial studies, as appropriate. They are considered the most probable scenario at this time. The higher and lower cases are provided to give additional insights into what loads could look like under different scenarios. These are not meant to be all-inclusive and may or may not capture some of the more ambitious and aspirational type DER scenarios associated with more renewables due to climate and other regional discussions. These can include, among other things, additional electrification of the transportation and heating sectors, and managed EV charging. The Company is actively monitoring these processes and will incorporate, as appropriate, new policies and scenarios as they become more likely.

Climate Scenarios

The Company provides a climate change scenario based on possible changes in weather over time. This scenario shows potential changes to summer peak loads should average temperatures and volatility increase over time. Figure 26 compares the base case, 50/50 summer peak forecast vs. alternative loads with higher average weather values.

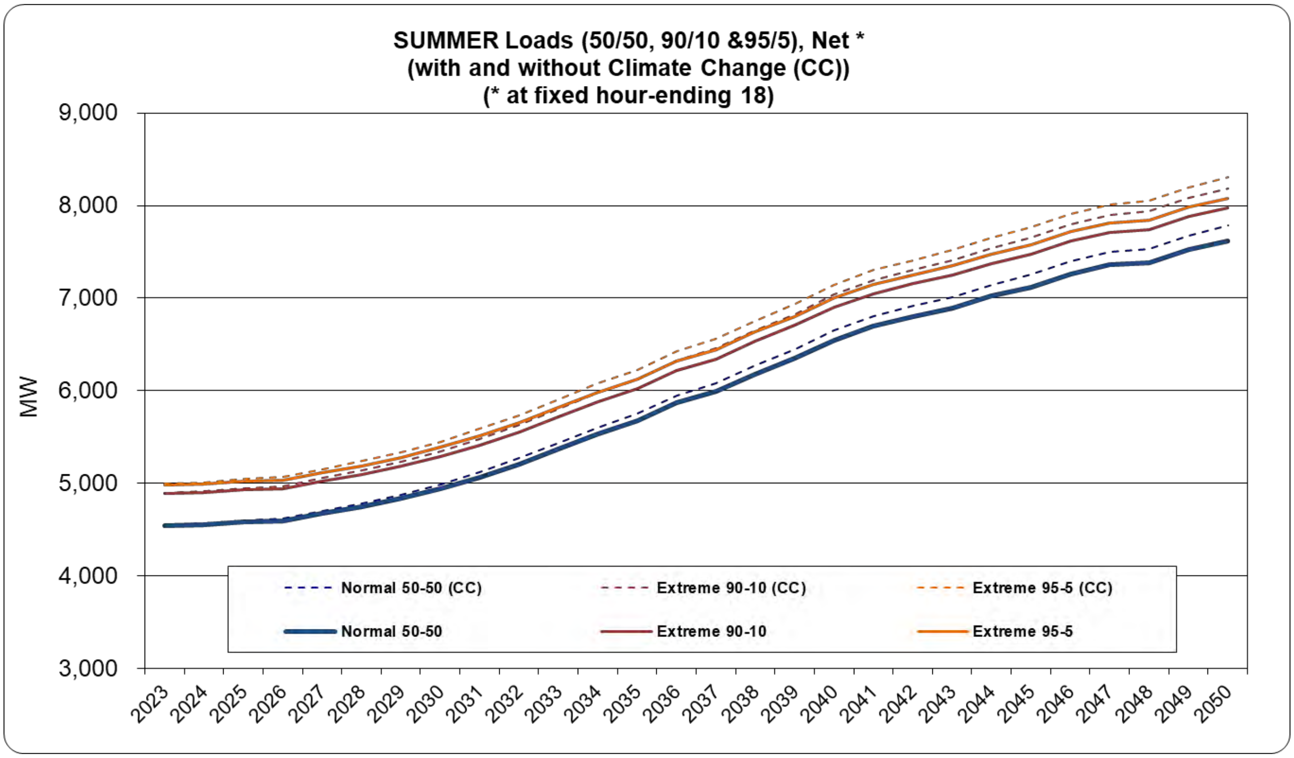


Figure 26 Summer Loads Base case and with Climate Change

The input assumption is a 0.7 degree rise in average temperatures per each ten years and a five percent increase in volatility over that same period. These increases are evenly divided across each year. The temperature increase is selected based on work that the NYISO performed relative to climate change.[22] This is assumed as a proxy for New England. Average temperature is a factor in each of the three weather scenarios. The volatility value of 5% is currently a placeholder. The NYISO report did not assume a value for this, however, since the 90/10 and 95/5 scenarios in this report do include variance in the modeling, a placeholder value was assumed for this exercise.

Table 3 shows the differences between the loads in the base case and the potential higher loads with the climate change assumptions for the three weather scenarios.

[22] *NYISO Climate Change Phase II Study*, page 4, April 2020.

Table 3 Comparison of Summer Loads between Base case and Climate Change Scenario for Year 2050

	50-50		90-10		95-5	
	Base	w/CC	Base	w/CC	Base	w/CC
Year 2050 (MWs)	7,620	7,781	7,978	8,187	8,080	8,302
Delta (MWs)		161		209		223
Delta (%)		2.1%		2.6%		2.8%

Comparison of 2022 Forecast to 2021 Forecast

This year is the first year that the peak forecast is provided for more than 15 years. The comparison to prior year's release can only be done for the next 14 years where the forecast horizon ends in last year's release.

Figure 27 provides a comparison of this year's summer peak forecast to last years and Figure 28 provides a comparison of this year's winter peak forecast to last years

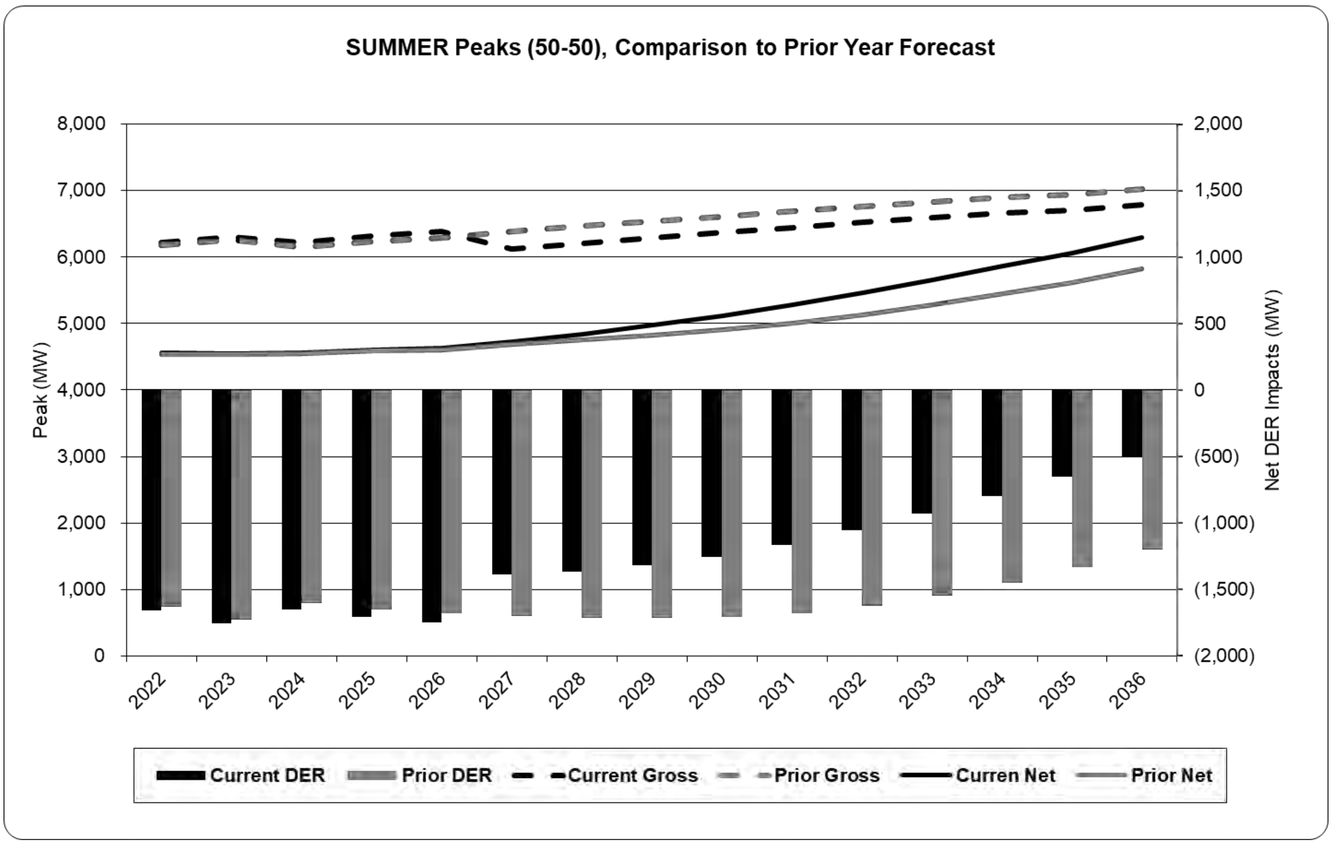


Figure 27 Comparison of current forecast to prior forecast, Gross and Net, Summer 50-50

The "Gross" summer peak load forecast is expected to be similar to the 2021 release for the next four years, and then step down due to the peak hour is expected to shift to later in the evening. The "Net" forecasts are similar in the next five years but becomes higher in later years driven by the lower net DER impacts.

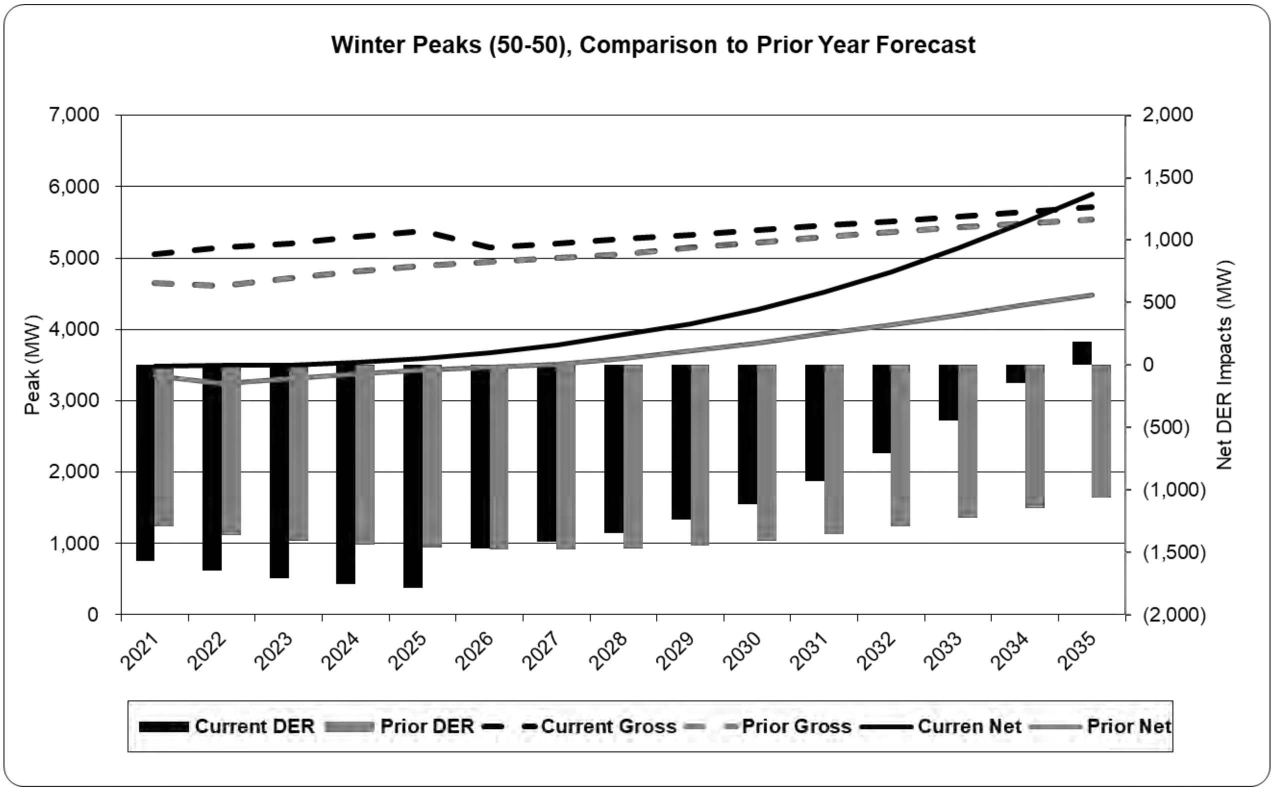


Figure 28 Comparison of current forecast to prior forecast, Gross and Net, Winter 50-50

The "Net" winter peak forecasts are expected to be higher than the 2021 release for the next 14 years. This is because of the joint effect from the higher projected "Gross" load now and lower net DER savings driven by electrifications in the transportation and heating sections.

Appendix A: Forecast Details

<u>MECO (COMPANY)</u>

MECO
Annual Peaks

AFTER DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	Peak Season (50-50)
2006	5,153		4,824		5,118		5,201		S
2007	4,733	-8.1%	4,791	-0.7%	5,075	-0.9%	5,155	-0.9%	S
2008	4,808	1.6%	4,844	1.1%	5,126	1.0%	5,206	1.0%	S
2009	4,518	-6.0%	4,760	-1.7%	5,040	-1.7%	5,119	-1.7%	S
2010	4,874	7.9%	4,739	-0.4%	5,029	-0.2%	5,111	-0.2%	S
2011	5,042	3.4%	4,694	-1.0%	4,974	-1.1%	5,053	-1.1%	S
2012	4,749	-5.8%	4,818	2.6%	5,089	2.3%	5,166	2.2%	S
2013	5,003	5.4%	4,764	-1.1%	5,043	-0.9%	5,123	-0.8%	S
2014	4,379	-12.5%	4,726	-0.8%	5,013	-0.6%	5,095	-0.5%	S
2015	4,384	0.1%	4,647	-1.7%	4,933	-1.6%	5,014	-1.6%	S
2016	4,556	3.9%	4,580	-1.4%	4,857	-1.5%	4,935	-1.6%	S
2017	4,314	-5.3%	4,518	-1.3%	4,800	-1.2%	4,880	-1.1%	S
2018	4,680	8.5%	4,535	0.4%	4,815	0.3%	4,894	0.3%	S
2019	4,339	-7.3%	4,404	-2.9%	4,671	-3.0%	4,746	-3.0%	S
2020	4,497	3.6%	4,610	4.7%	4,894	4.8%	4,974	4.8%	S
2021	4,643	3.2%	4,508	-2.2%	4,769	-2.5%	4,843	-2.6%	S
2022	4,657	0.3%	4,562	1.2%	4,904	2.8%	5,001	3.3%	S
2023	-	-	4,543	-0.4%	4,885	-0.4%	4,989	-0.2%	S
2024	-	-	4,562	0.4%	4,909	0.5%	5,014	0.5%	S
2025	-	-	4,607	1.0%	4,945	0.7%	5,049	0.7%	S
2026	-	-	4,636	0.6%	4,970	0.5%	5,064	0.3%	S
2027	-	-	4,732	2.1%	5,065	1.9%	5,160	1.9%	S
2028	-	-	4,845	2.4%	5,161	1.9%	5,255	1.8%	S
2029	-	-	4,973	2.6%	5,290	2.5%	5,380	2.4%	S
2030	-	-	5,116	2.9%	5,433	2.7%	5,523	2.7%	S
2031	-	-	5,281	3.2%	5,599	3.1%	5,689	3.0%	S
2032	-	-	5,465	3.5%	5,784	3.3%	5,874	3.2%	S
2033	-	-	5,663	3.6%	5,983	3.4%	6,073	3.4%	S
2034	-	-	5,870	3.6%	6,190	3.5%	6,280	3.4%	S
2035	-	-	6,056	3.2%	6,376	3.0%	6,467	3.0%	S
2036	-	-	6,315	4.3%	6,611	3.7%	6,702	3.6%	W
2037	-	-	6,754	7.0%	6,929	4.8%	6,978	4.1%	W
2038	-		7,150	5.9%	7,325	5.7%	7,375	5.7%	W
2039	-		7,563	5.8%	7,740	5.7%	7,790	5.6%	W
2040	-		8,009	5.9%	8,188	5.8%	8,239	5.8%	W
2041	-		8,357	4.3%	8,537	4.3%	8,588	4.2%	W
2042	-		8,698	4.1%	8,880	4.0%	8,932	4.0%	W
2043	-		9,011	3.6%	9,198	3.6%	9,252	3.6%	W
2044	-		9,314	3.4%	9,506	3.3%	9,560	3.3%	W
2045	-		9,572	2.8%	9,765	2.7%	9,820	2.7%	W
2046	-		9,799	2.4%	9,994	2.3%	10,049	2.3%	W
2047	-		10,014	2.2%	10,211	2.2%	10,266	2.2%	W
2048	-		10,218	2.0%	10,417	2.0%	10,473	2.0%	W
2049	-		10,326	1.1%	10,526	1.0%	10,582	1.0%	W
2050	-		10,389	0.6%	10,589	0.6%	10,646	0.6%	W

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.3%	-0.2%	-0.2%
Avg. last 10 yrs	-0.5%	-0.4%	-0.3%
Avg. last 5 yrs	0.2%	0.4%	0.5%
Base 2022			
Avg. next 5 yrs	0.7%	0.6%	0.6%
Avg. next 10 yrs	1.8%	1.7%	1.6%
Avg. next 15 yrs	2.6%	2.3%	2.2%
Avg. next 20 yrs	3.3%	3.0%	2.9%
Avg. next 25 yrs	3.2%	3.0%	2.9%

***** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heat pumps, and company demand response***

MECO
SUMMER Peaks

AFTER DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	WTHI ACTUAL
2006	5,153		4,824		5,118		5,201		83.9
2007	4,733	-8.1%	4,791	-0.7%	5,075	-0.9%	5,155	-0.9%	81.8
2008	4,808	1.6%	4,844	1.1%	5,126	1.0%	5,206	1.0%	82.0
2009	4,518	-6.0%	4,760	-1.7%	5,040	-1.7%	5,119	-1.7%	80.1
2010	4,874	7.9%	4,739	-0.4%	5,029	-0.2%	5,111	-0.2%	82.6
2011	5,042	3.4%	4,694	-1.0%	4,974	-1.1%	5,053	-1.1%	84.1
2012	4,749	-5.8%	4,818	2.6%	5,089	2.3%	5,166	2.2%	81.3
2013	5,003	5.4%	4,764	-1.1%	5,043	-0.9%	5,123	-0.8%	83.4
2014	4,379	-12.5%	4,726	-0.8%	5,013	-0.6%	5,095	-0.5%	80.3
2015	4,384	0.1%	4,647	-1.7%	4,933	-1.6%	5,014	-1.6%	79.5
2016	4,556	3.9%	4,580	-1.4%	4,857	-1.5%	4,935	-1.6%	82.3
2017	4,314	-5.3%	4,518	-1.3%	4,800	-1.2%	4,880	-1.1%	80.9
2018	4,680	8.5%	4,535	0.4%	4,815	0.3%	4,894	0.3%	82.7
2019	4,339	-7.3%	4,404	-2.9%	4,671	-3.0%	4,746	-3.0%	81.3
2020	4,497	3.6%	4,610	4.7%	4,894	4.8%	4,974	4.8%	81.0
2021	4,643	3.2%	4,508	-2.2%	4,769	-2.5%	4,843	-2.6%	83.4
2022	4,657	0.3%	4,562	1.2%	4,904	2.8%	5,001	3.3%	83.3
2023	-	-	4,543	-0.4%	4,885	-0.4%	4,989	-0.2%	-
2024	-	-	4,562	0.4%	4,909	0.5%	5,014	0.5%	-
2025	-	-	4,607	1.0%	4,945	0.7%	5,049	0.7%	-
2026	-	-	4,636	0.6%	4,970	0.5%	5,064	0.3%	-
2027	-	-	4,732	2.1%	5,065	1.9%	5,160	1.9%	-
2028	-	-	4,845	2.4%	5,161	1.9%	5,255	1.8%	-
2029	-	-	4,973	2.6%	5,290	2.5%	5,380	2.4%	-
2030	-	-	5,116	2.9%	5,433	2.7%	5,523	2.7%	-
2031	-	-	5,281	3.2%	5,599	3.1%	5,689	3.0%	-
2032	-	-	5,465	3.5%	5,784	3.3%	5,874	3.2%	-
2033	-	-	5,663	3.6%	5,983	3.4%	6,073	3.4%	-
2034	-	-	5,870	3.6%	6,190	3.5%	6,280	3.4%	-
2035	-	-	6,056	3.2%	6,376	3.0%	6,467	3.0%	-
2036	-	-	6,290	3.9%	6,611	3.7%	6,702	3.6%	-
2037	-	-	6,459	2.7%	6,780	2.6%	6,871	2.5%	-
2038	-		6,689	3.6%	7,010	3.4%	7,101	3.4%	-
2039	-		6,902	3.2%	7,224	3.1%	7,316	3.0%	-
2040	-		7,143	3.5%	7,466	3.3%	7,557	3.3%	-
2041	-		7,322	2.5%	7,645	2.4%	7,737	2.4%	-
2042	-		7,455	1.8%	7,779	1.7%	7,870	1.7%	-
2043	-		7,576	1.6%	7,900	1.6%	7,991	1.5%	-
2044	-		7,722	1.9%	8,046	1.9%	8,138	1.8%	-
2045	-		7,840	1.5%	8,165	1.5%	8,257	1.5%	-
2046	-		7,990	1.9%	8,316	1.8%	8,408	1.8%	-
2047	-		8,096	1.3%	8,422	1.3%	8,515	1.3%	-
2048	-		8,136	0.5%	8,462	0.5%	8,555	0.5%	-
2049	-		8,276	1.7%	8,603	1.7%	8,696	1.6%	-
2050	-		8,377	1.2%	8,705	1.2%	8,798	1.2%	-

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.3%	-0.2%	-0.2%
Avg. last 10 yrs	-0.5%	-0.4%	-0.3%
Avg. last 5 yrs	0.2%	0.4%	0.5%
Base 2022			
Avg. next 5 yrs	0.7%	0.6%	0.6%
Avg. next 10 yrs	1.8%	1.7%	1.6%
Avg. next 15 yrs	2.3%	2.2%	2.1%
Avg. next 20 yrs	2.5%	2.3%	2.3%
Avg. next 25 yrs	2.3%	2.2%	2.2%

WTHI

NORMAL	81.7
EXTREME 90/10	83.6
EXTREME 95/5	84.2

**** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response***

MECO	SUMMER 50/50 Peaks (MW) (before & after DERs)														
	SYSTEM PEAK								DER IMPACTS						
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2006	4,927	4,825	4,927	4,927	4,927	4,927	4,927	**4,824**	(103)	(0)	0.0	0.0	0.0	0.0	(103)
2007	4,925	4,792	4,924	4,925	4,925	4,925	4,925	**4,791**	(133)	(1)	0.0	0.0	0.0	0.0	(134)
2008	5,010	4,845	5,009	5,010	5,010	5,010	5,010	**4,844**	(164)	(1)	0.0	0.0	0.0	0.0	(165)
2009	4,966	4,763	4,963	4,966	4,966	4,966	4,966	**4,760**	(202)	(3)	0.0	0.0	0.0	0.0	(205)
2010	4,995	4,745	4,989	4,995	4,995	4,995	4,995	**4,739**	(249)	(6)	0.0	0.0	0.0	0.0	(255)
2011	5,007	4,706	4,995	5,007	5,007	5,007	5,007	**4,694**	(301)	(13)	0.0	0.0	0.0	0.0	(314)
2012	5,193	4,835	5,176	5,193	5,193	5,193	5,193	**4,818**	(358)	(17)	0.1	0.0	0.0	0.0	(375)
2013	5,274	4,845	5,192	5,274	5,274	5,274	5,274	**4,764**	(429)	(82)	0.2	0.0	0.0	0.0	(511)
2014	5,355	4,843	5,238	5,356	5,355	5,355	5,355	**4,726**	(512)	(117)	0.4	0.0	0.0	0.0	(629)
2015	5,364	4,759	5,251	5,364	5,364	5,364	5,364	**4,647**	(604)	(113)	0.7	0.0	0.0	0.0	(717)
2016	5,622	4,913	5,288	5,623	5,621	5,622	5,622	**4,580**	(709)	(334)	0.9	(0.3)	0.0	0.0	(1,042)
2017	5,568	4,752	5,340	5,570	5,561	5,568	5,568	**4,518**	(816)	(228)	1.4	(7.3)	(0.2)	0.0	(1,050)
2018	5,601	4,676	5,493	5,604	5,566	5,600	5,601	**4,535**	(925)	(108)	3.0	(34.9)	(1.2)	0.0	(1,066)
2019	5,633	4,596	5,511	5,637	5,569	5,621	5,633	**4,404**	(1,037)	(121)	4.2	(63.3)	(11.4)	0.2	(1,228)
2020	5,982	4,837	5,842	5,988	5,921	5,950	5,983	**4,610**	(1,145)	(140)	5.5	(60.8)	(32.1)	0.6	(1,372)
2021	6,027	4,792	5,863	6,035	5,967	5,958	6,028	**4,508**	(1,235)	(164)	7.6	(59.7)	(68.9)	1.1	(1,519)
2022	6,222	4,930	6,036	6,233	6,141	6,107	6,224	**4,562**	(1,292)	(186)	11.8	(80.7)	(114.9)	2.3	(1,659)
2023	6,300	4,969	6,094	6,320	6,217	6,139	6,305	**4,543**	(1,332)	(206)	19.6	(83.0)	(161.0)	4.4	(1,758)
2024	6,212	4,843	6,183	6,248	6,123	6,005	6,219	**4,562**	(1,368)	(29)	36.6	(88.4)	(207.0)	6.8	(1,649)
2025	6,315	4,915	6,284	6,370	6,222	6,068	6,326	**4,607**	(1,400)	(31)	54.4	(93.9)	(247.5)	10.1	(1,708)
2026	6,382	4,955	6,348	6,461	6,284	6,102	6,396	**4,636**	(1,427)	(34)	78.4	(98.2)	(279.8)	14.1	(1,747)
2027	6,121	4,671	6,121	6,234	6,045	6,129	6,138	**4,732**	(1,450)	0	112.2	(76.6)	8.1	17.0	(1,390)
2028	6,209	4,739	6,209	6,364	6,129	6,218	6,232	**4,845**	(1,470)	0	155.3	(80.3)	8.7	22.3	(1,364)
2029	6,292	4,805	6,292	6,506	6,208	6,301	6,320	**4,973**	(1,487)	0	214.1	(84.2)	9.1	28.3	(1,319)
2030	6,369	4,868	6,369	6,660	6,282	6,379	6,404	**5,116**	(1,501)	0	290.6	(87.4)	9.5	34.7	(1,253)
2031	6,445	4,932	6,445	6,832	6,355	6,454	6,487	**5,281**	(1,513)	0	387.8	(90.0)	9.8	42.0	(1,163)
2032	6,519	4,996	6,519	7,020	6,427	6,529	6,570	**5,465**	(1,523)	0	500.4	(92.4)	10.0	51.0	(1,054)
2033	6,595	5,063	6,595	7,219	6,500	6,605	6,657	**5,663**	(1,532)	0	623.7	(95.2)	10.2	61.7	(931)
2034	6,666	5,127	6,666	7,423	6,568	6,677	6,740	**5,870**	(1,539)	0	756.5	(97.8)	10.3	74.0	(796)
2035	6,708	5,162	6,708	7,604	6,607	6,718	6,795	**6,056**	(1,546)	0	896.7	(100.5)	10.4	87.5	(651)
2036	6,792	5,241	6,792	7,833	6,688	6,802	6,894	**6,290**	(1,551)	0	1,040.9	(103.5)	10.5	101.7	(502)
2037	6,814	5,257	6,814	7,996	6,708	6,825	6,931	**6,459**	(1,557)	0	1,181.8	(106.5)	10.6	116.4	(355)
2038	6,901	5,338	6,901	8,220	6,791	6,912	7,032	**6,689**	(1,563)	0	1,318.6	(109.9)	10.7	131.1	(213)
2039	6,969	5,400	6,969	8,428	6,856	6,980	7,115	**6,902**	(1,569)	0	1,458.9	(113.1)	10.7	145.5	(67)
2040	7,053	5,478	7,053	8,663	6,937	7,063	7,212	**7,143**	(1,575)	0	1,610.4	(115.4)	10.8	159.2	90
2041	7,132	5,552	7,132	8,837	7,015	7,143	7,304	**7,322**	(1,581)	0	1,704.9	(117.2)	10.8	172.0	190
2042	7,176	5,590	7,176	8,966	7,057	7,187	7,360	**7,455**	(1,587)	0	1,789.6	(118.6)	10.8	183.6	279
2043	7,218	5,626	7,218	9,084	7,098	7,229	7,412	**7,576**	(1,592)	0	1,865.5	(120.2)	10.8	193.9	358
2044	7,295	5,697	7,295	9,228	7,174	7,306	7,498	**7,722**	(1,598)	0	1,932.4	(121.6)	10.9	202.7	426
2045	7,356	5,751	7,356	9,346	7,232	7,366	7,566	**7,840**	(1,604)	0	1,990.6	(123.2)	10.9	210.1	484
2046	7,457	5,847	7,457	9,498	7,332	7,468	7,673	**7,990**	(1,610)	0	2,040.7	(125.0)	10.9	216.1	533
2047	7,524	5,908	7,524	9,607	7,397	7,535	7,744	**8,096**	(1,616)	0	2,083.3	(126.8)	10.9	220.7	572
2048	7,532	5,910	7,532	9,651	7,403	7,543	7,756	**8,136**	(1,622)	0	2,119.4	(128.5)	10.9	224.0	604
2049	7,647	6,019	7,647	9,797	7,516	7,658	7,873	**8,276**	(1,628)	0	2,149.9	(130.3)	10.9	226.2	629
2050	7,729	6,095	7,729	9,904	7,597	7,740	7,956	**8,377**	(1,633)	0	2,175.8	(132.1)	10.9	227.1	648

Avg. last 15 yrs	1.6%	0.2%	1.4%	1.6%	1.5%	1.4%	1.6%	-0.3%
Avg. last 10 yrs	1.8%	0.2%	1.5%	1.8%	1.7%	1.6%	1.8%	-0.5%
Avg. last 5 yrs	2.2%	0.7%	2.5%	2.3%	2.0%	1.9%	2.3%	0.2%
Base 2022								
Avg. next 5 yrs	-0.3%	-1.1%	0.3%	0.0%	-0.3%	0.1%	-0.3%	0.7%
Avg. next 10 yrs	0.5%	0.1%	0.8%	1.2%	0.5%	0.7%	0.5%	1.8%
Avg. next 15 yrs	0.6%	0.4%	0.8%	1.7%	0.6%	0.7%	0.7%	2.3%
Avg. next 20 yrs	0.7%	0.6%	0.9%	1.8%	0.7%	0.8%	0.8%	2.5%
Avg. next 25 yrs	0.8%	0.7%	0.9%	1.7%	0.7%	0.8%	0.9%	2.3%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating Pump Cooling (reduces load)

MECO
WINTER Peaks

after DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 10-90 (MW)	Extreme 10-90 (% Grwth)	Extreme 05-95 (MW)	Extreme 05-95 (% Grwth)	HDD_wtd ACTUAL
2006	3,875		3,860		3,975		4,007		49.1
2007	3,888	0.4%	3,822	-1.0%	3,933	-1.0%	3,965	-1.1%	48.9
2008	3,729	-4.1%	3,796	-0.7%	3,917	-0.4%	3,952	-0.3%	42.3
2009	3,720	-0.3%	3,821	0.6%	3,937	0.5%	3,970	0.5%	38.5
2010	3,807	2.4%	3,679	-3.7%	3,815	-3.1%	3,854	-2.9%	55.1
2011	3,558	-6.5%	3,675	-0.1%	3,804	-0.3%	3,840	-0.3%	46.9
2012	3,760	5.7%	3,723	1.3%	3,853	1.3%	3,889	1.3%	50.0
2013	3,881	3.2%	3,906	4.9%	4,044	5.0%	4,083	5.0%	46.5
2014	3,662	-5.6%	3,611	-7.5%	3,733	-7.7%	3,767	-7.7%	53.1
2015	3,437	-6.2%	3,514	-2.7%	3,628	-2.8%	3,660	-2.8%	43.9
2016	3,499	1.8%	3,471	-1.2%	3,610	-0.5%	3,649	-0.3%	48.0
2017	3,676	5.1%	3,485	0.4%	3,654	1.2%	3,702	1.5%	56.5
2018	3,692	0.4%	3,586	2.9%	3,731	2.1%	3,772	1.9%	53.4
2019	3,291	-10.9%	3,378	-5.8%	3,521	-5.6%	3,561	-5.6%	43.2
2020	3,333	1.3%	3,498	3.6%	3,634	3.2%	3,672	3.1%	41.6
2021	3,529	5.9%	3,486	-0.3%	3,631	-0.1%	3,672	0.0%	47.0
2022	-	-	3,498	0.3%	3,652	0.6%	3,695	0.6%	-
2023		-	3,503	0.1%	3,659	0.2%	3,703	0.2%	
2024		-	3,544	1.2%	3,703	1.2%	3,748	1.2%	
2025	-	-	3,586	1.2%	3,747	1.2%	3,792	1.2%	-
2026	-	-	3,677	2.5%	3,831	2.2%	3,874	2.2%	-
2027	-	-	3,782	2.9%	3,938	2.8%	3,982	2.8%	-
2028	-	-	3,930	3.9%	4,087	3.8%	4,132	3.8%	-
2029	-	-	4,081	3.9%	4,240	3.7%	4,285	3.7%	-
2030	-	-	4,278	4.8%	4,439	4.7%	4,484	4.6%	-
2031	-	-	4,522	5.7%	4,685	5.6%	4,731	5.5%	-
2032	-	-	4,809	6.3%	4,974	6.2%	5,021	6.1%	-
2033	-	-	5,138	6.8%	5,305	6.7%	5,352	6.6%	-
2034	-	-	5,501	7.1%	5,670	6.9%	5,717	6.8%	-
2035	-	-	5,899	7.2%	6,069	7.1%	6,118	7.0%	-
2036	-	-	6,315	7.1%	6,488	6.9%	6,536	6.8%	-
2037	-		6,754	7.0%	6,929	6.8%	6,978	6.8%	-
2038	-		7,150	5.9%	7,325	5.7%	7,375	5.7%	-
2039	-		7,563	5.8%	7,740	5.7%	7,790	5.6%	-
2040	-		8,009	5.9%	8,188	5.8%	8,239	5.8%	-
2041	-		8,357	4.3%	8,537	4.3%	8,588	4.2%	-
2042	-		8,698	4.1%	8,880	4.0%	8,932	4.0%	-
2043	-		9,011	3.6%	9,198	3.6%	9,252	3.6%	-
2044	-		9,314	3.4%	9,506	3.3%	9,560	3.3%	-
2045	-		9,572	2.8%	9,765	2.7%	9,820	2.7%	-
2046	-		9,799	2.4%	9,994	2.3%	10,049	2.3%	-
2047	-		10,014	2.2%	10,211	2.2%	10,266	2.2%	-
2048	-		10,218	2.0%	10,417	2.0%	10,473	2.0%	-
2049	-		10,326	1.1%	10,526	1.0%	10,582	1.0%	-
2050	-		10,389	0.6%	10,589	0.6%	10,646	0.6%	-

	Normal 50-50	Extreme 10-90	Extreme 05-95
Avg. last 15 yrs	-0.7%	-0.6%	-0.6%
Avg. last 10 yrs	-0.5%	-0.5%	-0.4%
Avg. last 5 yrs	0.1%	0.1%	0.1%
Base 2021			
Avg. next 5 yrs	1.1%	1.1%	1.1%
Avg. next 10 yrs	2.6%	2.6%	2.6%
Avg. next 15 yrs	4.0%	3.9%	3.9%
Avg. next 20 yrs	4.5%	4.4%	4.3%
Avg. next 25 yrs	4.2%	4.1%	4.1%

HDD_wtd

NORMAL	47.9
EXTREME 90/10	55.6
EXTREME 95/5	57.7

** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response (solar and demand response are zero at times of winter peak)*

MECO — WINTER 50/50 Peaks (MW) (before & after DERs)

Calendar Year	SYSTEM PEAK: Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	DER IMPACTS: EE	PV	EV	DR	ES	EH	DER
2006	4,042	3,860	4,042	4,042	4,042	4,042	4,042	**3,860**	(181)	0	0.0	0.0	0.0	0.0	(181)
2007	4,060	3,822	4,060	4,060	4,060	4,060	4,060	**3,822**	(238)	0	0.0	0.0	0.0	0.0	(238)
2008	4,068	3,796	4,068	4,068	4,068	4,068	4,068	**3,796**	(272)	0	0.0	0.0	0.0	0.0	(272)
2009	4,156	3,821	4,156	4,156	4,156	4,156	4,156	**3,821**	(336)	0	0.0	0.0	0.0	0.0	(336)
2010	4,071	3,679	4,071	4,071	4,071	4,071	4,071	**3,679**	(392)	0	0.0	0.0	0.0	0.0	(392)
2011	4,127	3,675	4,127	4,127	4,127	4,127	4,127	**3,675**	(452)	0	0.0	0.0	0.0	0.0	(452)
2012	4,242	3,723	4,242	4,243	4,242	4,242	4,242	**3,723**	(519)	0	0.3	0.0	0.0	0.0	(519)
2013	4,515	3,905	4,515	4,515	4,515	4,515	4,515	**3,906**	(609)	0	0.5	0.0	0.0	0.0	(609)
2014	4,317	3,610	4,317	4,318	4,317	4,317	4,317	**3,611**	(707)	0	1.0	0.0	0.0	0.0	(706)
2015	4,328	3,512	4,328	4,330	4,328	4,328	4,328	**3,514**	(816)	0	1.6	0.0	0.0	0.0	(814)
2016	4,397	3,469	4,397	4,399	4,397	4,397	4,397	**3,471**	(928)	0	1.8	0.0	0.0	0.0	(926)
2017	4,526	3,483	4,526	4,528	4,526	4,525	4,526	**3,485**	(1,043)	0	2.8	0.0	(0.4)	0.0	(1,041)
2018	4,753	3,584	4,753	4,757	4,753	4,751	4,753	**3,586**	(1,169)	0	4.4	0.0	(1.8)	0.0	(1,166)
2019	4,683	3,390	4,683	4,689	4,683	4,665	4,684	**3,378**	(1,293)	0	6.1	0.0	(18.4)	0.7	(1,305)
2020	4,947	3,531	4,947	4,955	4,947	4,905	4,949	**3,498**	(1,416)	0	7.7	0.0	(42.4)	2.2	(1,449)
2021	5,055	3,560	5,055	5,066	5,055	4,966	5,059	**3,486**	(1,496)	0	11.1	0.0	(88.7)	4.2	(1,569)
2022	5,143	3,605	5,143	5,161	5,143	5,008	5,153	**3,498**	(1,538)	0	17.8	0.0	(135.1)	9.7	(1,645)
2023	5,208	3,634	5,208	5,238	5,208	5,027	5,229	**3,503**	(1,575)	0	29.9	0.0	(181.4)	20.7	(1,706)
2024	5,300	3,690	5,300	5,346	5,300	5,072	5,335	**3,544**	(1,610)	0	46.6	0.0	(227.8)	35.4	(1,755)
2025	5,371	3,732	5,371	5,440	5,371	5,107	5,421	**3,586**	(1,639)	0	68.5	0.0	(264.5)	50.2	(1,785)
2026	5,143	3,479	5,143	5,274	5,143	5,152	5,203	**3,677**	(1,665)	0	130.4	0.0	8.2	59.7	(1,466)
2027	5,199	3,512	5,199	5,382	5,199	5,207	5,277	**3,782**	(1,686)	0	183.0	0.0	8.8	78.1	(1,416)
2028	5,274	3,570	5,274	5,526	5,274	5,283	5,373	**3,930**	(1,704)	0	251.9	0.0	9.4	98.6	(1,344)
2029	5,323	3,603	5,323	5,670	5,323	5,332	5,443	**4,081**	(1,720)	0	347.7	0.0	9.8	120.8	(1,241)
2030	5,388	3,655	5,388	5,856	5,388	5,399	5,533	**4,278**	(1,733)	0	467.8	0.0	10.1	144.2	(1,111)
2031	5,453	3,708	5,453	6,074	5,453	5,463	5,634	**4,522**	(1,744)	0	621.7	0.0	10.4	181.9	(930)
2032	5,516	3,763	5,516	6,306	5,516	5,527	5,763	**4,809**	(1,754)	0	789.5	0.0	10.6	246.4	(707)
2033	5,580	3,819	5,580	6,553	5,580	5,591	5,916	**5,138**	(1,762)	0	973.1	0.0	10.8	336.0	(442)
2034	5,642	3,873	5,642	6,811	5,642	5,653	6,090	**5,501**	(1,769)	0	1,168.9	0.0	10.9	448.4	(140)
2035	5,709	3,935	5,709	7,082	5,709	5,720	6,290	**5,899**	(1,775)	0	1,372.7	0.0	11.0	580.9	190
2036	5,777	3,996	5,777	7,354	5,777	5,788	6,507	**6,315**	(1,780)	0	1,577.8	0.0	11.1	730.1	539
2037	5,859	4,073	5,859	7,637	5,859	5,870	6,751	**6,754**	(1,786)	0	1,778.0	0.0	11.2	892.2	895
2038	5,896	4,104	5,896	7,867	5,896	5,907	6,959	**7,150**	(1,792)	0	1,971.4	0.0	11.2	1,063.4	1,254
2039	5,940	4,143	5,940	8,110	5,940	5,952	7,180	**7,563**	(1,798)	0	2,169.9	0.0	11.3	1,239.4	1,623
2040	5,999	4,195	5,999	8,386	5,999	6,010	7,415	**8,009**	(1,804)	0	2,386.6	0.0	11.3	1,416.0	2,010
2041	6,049	4,239	6,049	8,566	6,049	6,060	7,638	**8,357**	(1,810)	0	2,516.8	0.0	11.3	1,589.2	2,308
2042	6,112	4,297	6,112	8,747	6,112	6,124	7,867	**8,698**	(1,815)	0	2,634.8	0.0	11.4	1,755.2	2,586
2043	6,171	4,350	6,171	8,911	6,171	6,183	8,082	**9,011**	(1,821)	0	2,739.7	0.0	11.4	1,910.3	2,840
2044	6,440	4,613	6,440	9,209	6,440	6,029	8,785	**9,314**	(1,827)	0	2,768.1	0.0	(411.6)	2,344.3	2,874
2045	6,485	4,652	6,485	9,332	6,485	6,072	8,971	**9,572**	(1,833)	0	2,846.9	0.0	(412.4)	2,485.9	3,087
2046	6,530	4,692	6,530	9,445	6,530	6,118	9,136	**9,799**	(1,839)	0	2,914.7	0.0	(412.4)	2,605.3	3,269
2047	6,598	4,754	6,598	9,571	6,598	6,186	9,299	**10,014**	(1,845)	0	2,972.4	0.0	(412.4)	2,700.4	3,416
2048	6,690	4,839	6,690	9,712	6,690	6,278	9,459	**10,218**	(1,850)	0	3,021.6	0.0	(412.4)	2,769.5	3,528
2049	6,720	4,863	6,720	9,783	6,720	6,307	9,531	**10,326**	(1,856)	0	3,063.5	0.0	(412.4)	2,811.4	3,606
2050	6,738	4,876	6,738	9,838	6,738	6,326	9,564	**10,389**	(1,862)	0	3,099.3	0.0	(412.4)	2,825.4	3,650

	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)
		-						
Avg. last 15 yrs	1.5%	-0.5%	1.5%	1.5%	1.5%	1.4%	1.5%	-0.7%
Avg. last 10 yrs	2.0%	-0.3%	2.0%	2.1%	2.0%	1.9%	2.1%	-0.5%
Avg. last 5 yrs	2.8%	0.5%	2.8%	2.9%	2.8%	2.5%	2.8%	0.1%
Base 2021								
Avg. next 5 yrs	0.3%	-0.5%	0.3%	0.8%	0.3%	0.7%	0.6%	1.1%
Avg. next 10 yrs	0.8%	0.4%	0.8%	1.8%	0.8%	1.0%	1.1%	2.6%
Avg. next 15 yrs	0.9%	0.8%	0.9%	2.5%	0.9%	1.0%	1.7%	4.0%
Avg. next 20 yrs	1.0%	0.9%	1.0%	2.8%	1.0%	1.1%	2.2%	4.7%
Avg. next 25 yrs	1.1%	1.2%	1.1%	2.6%	1.1%	0.9%	2.5%	4.3%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating/Cooling (ADDs to load)

NEMA Zone (Northeast Massachusetts)

NEMA
Annual Peaks

AFTER DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	Peak Season (50-50)
2006	1,262		1,190		1,282		1,308		S
2007	1,155	-8.5%	1,166	-2.1%	1,252	-2.3%	1,277	-2.4%	S
2008	1,122	-2.8%	1,174	0.7%	1,264	0.9%	1,289	1.0%	S
2009	1,115	-0.6%	1,179	0.4%	1,265	0.1%	1,289	0.0%	S
2010	1,203	7.9%	1,205	2.2%	1,292	2.2%	1,317	2.2%	S
2011	1,259	4.6%	1,172	-2.7%	1,257	-2.7%	1,281	-2.7%	S
2012	1,169	-7.1%	1,195	2.0%	1,281	1.9%	1,305	1.9%	S
2013	1,227	4.9%	1,172	-2.0%	1,257	-1.9%	1,281	-1.8%	S
2014	1,094	-10.9%	1,155	-1.4%	1,242	-1.2%	1,266	-1.1%	S
2015	1,082	-1.0%	1,131	-2.1%	1,218	-1.9%	1,243	-1.8%	S
2016	1,126	4.0%	1,086	-4.0%	1,168	-4.2%	1,191	-4.2%	S
2017	1,044	-7.3%	1,076	-0.9%	1,160	-0.7%	1,183	-0.6%	S
2018	1,150	10.2%	1,094	1.7%	1,181	1.8%	1,206	1.9%	S
2019	1,078	-6.3%	1,076	-1.7%	1,158	-2.0%	1,181	-2.0%	S
2020	1,136	5.4%	1,189	10.5%	1,281	10.6%	1,307	10.7%	S
2021	1,175	3.4%	1,074	-9.7%	1,170	-8.6%	1,198	-8.4%	S
2022	1,176	0.1%	1,114	3.7%	1,204	2.9%	1,230	2.7%	S
2023	-	-	1,120	0.6%	1,207	0.2%	1,232	0.1%	S
2024	-	-	1,135	1.3%	1,222	1.2%	1,247	1.2%	S
2025	-	-	1,154	1.7%	1,241	1.5%	1,265	1.5%	S
2026	-	-	1,168	1.3%	1,256	1.2%	1,280	1.2%	S
2027	-	-	1,196	2.4%	1,284	2.2%	1,308	2.2%	S
2028	-	-	1,225	2.4%	1,312	2.2%	1,337	2.2%	S
2029	-	-	1,258	2.7%	1,345	2.5%	1,370	2.5%	S
2030	-	-	1,296	3.0%	1,383	2.8%	1,408	2.8%	S
2031	-	-	1,341	3.5%	1,429	3.3%	1,454	3.2%	S
2032	-	-	1,392	3.8%	1,480	3.6%	1,505	3.5%	S
2033	-	-	1,447	4.0%	1,535	3.7%	1,560	3.7%	S
2034	-	-	1,517	4.8%	1,593	3.8%	1,618	3.7%	W
2035	-	-	1,632	7.6%	1,690	6.1%	1,706	5.4%	W
2036	-	-	1,752	7.3%	1,810	7.1%	1,827	7.1%	W
2037	-	-	1,878	7.2%	1,937	7.0%	1,954	7.0%	W
2038	-		1,990	6.0%	2,050	5.8%	2,067	5.8%	W
2039	-		2,107	5.9%	2,167	5.7%	2,185	5.7%	W
2040	-		2,235	6.0%	2,295	5.9%	2,313	5.9%	W
2041	-		2,331	4.3%	2,393	4.2%	2,410	4.2%	W
2042	-		2,427	4.1%	2,489	4.0%	2,507	4.0%	W
2043	-		2,514	3.6%	2,578	3.6%	2,597	3.6%	W
2044	-		2,598	3.3%	2,664	3.3%	2,683	3.3%	W
2045	-		2,669	2.7%	2,736	2.7%	2,754	2.7%	W
2046	-		2,732	2.4%	2,799	2.3%	2,818	2.3%	W
2047	-		2,793	2.2%	2,861	2.2%	2,880	2.2%	W
2048	-		2,853	2.1%	2,921	2.1%	2,941	2.1%	W
2049	-		2,884	1.1%	2,953	1.1%	2,972	1.1%	W
2050	-		2,903	0.7%	2,972	0.6%	2,992	0.6%	W

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.3%	-0.3%	-0.2%
Avg. last 10 yrs	-0.7%	-0.6%	-0.6%
Avg. last 5 yrs	0.7%	0.8%	0.8%
Base 2022			
Avg. next 5 yrs	1.4%	1.3%	1.2%
Avg. next 10 yrs	2.3%	2.1%	2.0%
Avg. next 15 yrs	3.5%	3.2%	3.1%
Avg. next 20 yrs	4.0%	3.7%	3.6%
Avg. next 25 yrs	3.7%	3.5%	3.5%

***** *impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heat pumps, and company demand response*

NEMA
SUMMER Peaks

AFTER DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	WTHI ACTUAL
2006	1,262		1,190		1,282		1,308		84.5
2007	1,155	-8.5%	1,166	-2.1%	1,252	-2.3%	1,277	-2.4%	82.7
2008	1,122	-2.8%	1,174	0.7%	1,264	0.9%	1,289	1.0%	82.3
2009	1,115	-0.6%	1,179	0.4%	1,265	0.1%	1,289	0.0%	81.0
2010	1,203	7.9%	1,205	2.2%	1,292	2.2%	1,317	2.2%	82.6
2011	1,259	4.6%	1,172	-2.7%	1,257	-2.7%	1,281	-2.7%	85.7
2012	1,169	-7.1%	1,195	2.0%	1,281	1.9%	1,305	1.9%	82.0
2013	1,227	4.9%	1,172	-2.0%	1,257	-1.9%	1,281	-1.8%	84.2
2014	1,094	-10.9%	1,155	-1.4%	1,242	-1.2%	1,266	-1.1%	81.1
2015	1,082	-1.0%	1,131	-2.1%	1,218	-1.9%	1,243	-1.8%	81.4
2016	1,126	4.0%	1,086	-4.0%	1,168	-4.2%	1,191	-4.2%	84.1
2017	1,044	-7.3%	1,076	-0.9%	1,160	-0.7%	1,183	-0.6%	82.0
2018	1,150	10.2%	1,094	1.7%	1,181	1.8%	1,206	1.9%	84.2
2019	1,078	-6.3%	1,076	-1.7%	1,158	-2.0%	1,181	-2.0%	82.7
2020	1,136	5.4%	1,189	10.5%	1,281	10.6%	1,307	10.7%	81.4
2021	1,175	3.4%	1,074	-9.7%	1,170	-8.6%	1,198	-8.4%	85.3
2022	1,176	0.1%	1,114	3.7%	1,204	2.9%	1,230	2.7%	84.5
2023	-	-	1,120	0.6%	1,207	0.2%	1,232	0.1%	-
2024	-	-	1,135	1.3%	1,222	1.2%	1,247	1.2%	-
2025	-	-	1,154	1.7%	1,241	1.5%	1,265	1.5%	-
2026	-	-	1,168	1.3%	1,256	1.2%	1,280	1.2%	-
2027	-	-	1,196	2.4%	1,284	2.2%	1,308	2.2%	-
2028	-	-	1,225	2.4%	1,312	2.2%	1,337	2.2%	-
2029	-	-	1,258	2.7%	1,345	2.5%	1,370	2.5%	-
2030	-	-	1,296	3.0%	1,383	2.8%	1,408	2.8%	-
2031	-	-	1,341	3.5%	1,429	3.3%	1,454	3.2%	-
2032	-	-	1,392	3.8%	1,480	3.6%	1,505	3.5%	-
2033	-	-	1,447	4.0%	1,535	3.7%	1,560	3.7%	-
2034	-	-	1,505	4.0%	1,593	3.8%	1,618	3.7%	-
2035	-	-	1,560	3.6%	1,648	3.4%	1,673	3.4%	-
2036	-	-	1,625	4.2%	1,713	4.0%	1,738	3.9%	-
2037	-	-	1,676	3.1%	1,764	3.0%	1,789	2.9%	-
2038	-		1,739	3.8%	1,827	3.6%	1,852	3.6%	-
2039	-		1,800	3.5%	1,888	3.3%	1,913	3.3%	-
2040	-		1,867	3.7%	1,955	3.6%	1,980	3.5%	-
2041	-		1,915	2.6%	2,004	2.5%	2,029	2.4%	-
2042	-		1,953	1.9%	2,041	1.9%	2,066	1.8%	-
2043	-		1,986	1.7%	2,075	1.7%	2,100	1.6%	-
2044	-		2,025	1.9%	2,113	1.8%	2,138	1.8%	-
2045	-		2,056	1.6%	2,145	1.5%	2,170	1.5%	-
2046	-		2,093	1.8%	2,182	1.7%	2,207	1.7%	-
2047	-		2,121	1.3%	2,209	1.2%	2,234	1.2%	-
2048	-		2,133	0.6%	2,221	0.6%	2,247	0.5%	-
2049	-		2,166	1.6%	2,255	1.5%	2,280	1.5%	-
2050	-		2,190	1.1%	2,279	1.1%	2,304	1.1%	-

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.3%	-0.3%	-0.2%
Avg. last 10 yrs	-0.7%	-0.6%	-0.6%
Avg. last 5 yrs	0.7%	0.8%	0.8%
Base 2022			
Avg. next 5 yrs	1.4%	1.3%	1.2%
Avg. next 10 yrs	2.3%	2.1%	2.0%
Avg. next 15 yrs	2.8%	2.6%	2.5%
Avg. next 20 yrs	2.8%	2.7%	2.6%
Avg. next 25 yrs	2.6%	2.5%	2.4%

WTHI

NORMAL	82.7
EXTREME 90/10	85.0
EXTREME 95/5	85.6

*** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response***

NEMA	SUMMER 50/50 Peaks (MW) (before & after DERs)														
	SYSTEM PEAK								DER IMPACTS						
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2006	1,215	1,190	1,215	1,215	1,215	1,215	1,215	**1,190**	(24)	(0)	0.0	0.0	0.0	0.0	(25)
2007	1,198	1,166	1,197	1,198	1,198	1,198	1,198	**1,166**	(32)	(0)	0.0	0.0	0.0	0.0	(32)
2008	1,213	1,174	1,213	1,213	1,213	1,213	1,213	**1,174**	(39)	(0)	0.0	0.0	0.0	0.0	(39)
2009	1,228	1,180	1,227	1,228	1,228	1,228	1,228	**1,179**	(48)	(1)	0.0	0.0	0.0	0.0	(49)
2010	1,266	1,206	1,265	1,266	1,266	1,266	1,266	**1,205**	(60)	(2)	0.0	0.0	0.0	0.0	(62)
2011	1,247	1,175	1,245	1,247	1,247	1,247	1,247	**1,172**	(73)	(3)	0.0	0.0	0.0	0.0	(76)
2012	1,284	1,197	1,282	1,284	1,284	1,284	1,284	**1,195**	(87)	(1)	0.0	0.0	0.0	0.0	(88)
2013	1,283	1,178	1,276	1,283	1,283	1,283	1,283	**1,172**	(104)	(7)	0.1	0.0	0.0	0.0	(111)
2014	1,297	1,173	1,280	1,298	1,297	1,297	1,297	**1,155**	(125)	(18)	0.1	0.0	0.0	0.0	(142)
2015	1,295	1,147	1,278	1,295	1,295	1,295	1,295	**1,131**	(147)	(16)	0.2	0.0	0.0	0.0	(164)
2016	1,296	1,123	1,258	1,297	1,296	1,296	1,296	**1,086**	(173)	(38)	0.3	(0.1)	0.0	0.0	(211)
2017	1,309	1,110	1,276	1,309	1,307	1,309	1,309	**1,076**	(199)	(33)	0.4	(1.8)	(0.1)	0.0	(233)
2018	1,343	1,118	1,328	1,344	1,335	1,343	1,343	**1,094**	(226)	(15)	0.9	(8.4)	(0.3)	0.0	(249)
2019	1,363	1,110	1,345	1,364	1,348	1,360	1,363	**1,076**	(253)	(18)	1.3	(15.3)	(2.8)	0.0	(287)
2020	1,509	1,229	1,489	1,511	1,495	1,502	1,510	**1,189**	(280)	(20)	1.7	(14.7)	(7.8)	0.1	(321)
2021	1,427	1,125	1,405	1,430	1,413	1,411	1,428	**1,074**	(303)	(23)	2.3	(14.5)	(16.7)	0.3	(354)
2022	1,500	1,183	1,474	1,503	1,480	1,472	1,500	**1,114**	(317)	(26)	3.6	(19.6)	(27.8)	0.6	(386)
2023	1,453	1,126	1,453	1,460	1,438	1,454	1,454	**1,120**	(327)	0	7.4	(15.1)	1.0	0.9	(333)
2024	1,473	1,136	1,473	1,484	1,456	1,474	1,474	**1,135**	(336)	0	11.8	(16.1)	1.3	1.5	(338)
2025	1,494	1,150	1,494	1,511	1,477	1,495	1,496	**1,154**	(344)	0	17.5	(17.1)	1.6	2.2	(340)
2026	1,507	1,156	1,507	1,532	1,489	1,509	1,510	**1,168**	(351)	0	25.2	(17.9)	1.8	3.0	(339)
2027	1,530	1,173	1,530	1,566	1,512	1,532	1,534	**1,196**	(357)	0	35.6	(18.6)	2.0	4.1	(334)
2028	1,549	1,187	1,549	1,598	1,530	1,551	1,555	**1,225**	(362)	0	49.2	(19.5)	2.1	5.4	(324)
2029	1,567	1,201	1,567	1,635	1,547	1,569	1,574	**1,258**	(366)	0	67.9	(20.4)	2.2	6.9	(309)
2030	1,584	1,214	1,584	1,676	1,562	1,586	1,592	**1,296**	(369)	0	92.2	(21.2)	2.3	8.4	(288)
2031	1,600	1,227	1,600	1,723	1,578	1,602	1,610	**1,341**	(373)	0	123.0	(21.8)	2.4	10.2	(259)
2032	1,616	1,241	1,616	1,775	1,594	1,618	1,628	**1,392**	(375)	0	158.7	(22.4)	2.4	12.4	(224)
2033	1,632	1,255	1,632	1,830	1,609	1,635	1,647	**1,447**	(377)	0	197.8	(23.1)	2.5	15.0	(185)
2034	1,648	1,269	1,648	1,888	1,624	1,650	1,666	**1,505**	(379)	0	239.9	(23.7)	2.5	18.0	(142)
2035	1,657	1,276	1,657	1,941	1,632	1,659	1,678	**1,560**	(381)	0	284.4	(24.4)	2.5	21.3	(97)
2036	1,675	1,293	1,675	2,005	1,650	1,677	1,700	**1,625**	(382)	0	330.1	(25.1)	2.6	24.8	(50)
2037	1,680	1,296	1,680	2,054	1,654	1,682	1,708	**1,676**	(384)	0	374.8	(25.9)	2.6	28.3	(4)
2038	1,699	1,313	1,699	2,117	1,672	1,701	1,730	**1,739**	(385)	0	418.1	(26.7)	2.6	31.9	41
2039	1,713	1,327	1,713	2,176	1,686	1,716	1,749	**1,800**	(387)	0	462.5	(27.5)	2.6	35.4	86
2040	1,731	1,343	1,731	2,242	1,703	1,734	1,770	**1,867**	(388)	0	510.6	(28.0)	2.6	38.8	136
2041	1,748	1,359	1,748	2,289	1,720	1,751	1,790	**1,915**	(390)	0	540.5	(28.4)	2.6	41.9	167
2042	1,758	1,367	1,758	2,325	1,729	1,760	1,802	**1,953**	(391)	0	567.4	(28.8)	2.6	44.7	195
2043	1,767	1,374	1,767	2,358	1,738	1,769	1,814	**1,986**	(393)	0	591.5	(29.2)	2.6	47.2	220
2044	1,784	1,390	1,784	2,396	1,754	1,786	1,833	**2,025**	(394)	0	612.7	(29.5)	2.6	49.4	241
2045	1,797	1,401	1,797	2,428	1,767	1,799	1,848	**2,056**	(395)	0	631.2	(29.9)	2.6	51.2	260
2046	1,818	1,421	1,818	2,466	1,788	1,821	1,871	**2,093**	(397)	0	647.1	(30.3)	2.6	52.6	275
2047	1,833	1,434	1,833	2,494	1,802	1,835	1,887	**2,121**	(398)	0	660.7	(30.8)	2.6	53.7	288
2048	1,835	1,435	1,835	2,507	1,803	1,837	1,889	**2,133**	(400)	0	672.2	(31.2)	2.6	54.5	298
2049	1,859	1,458	1,859	2,541	1,828	1,862	1,914	**2,166**	(401)	0	682.0	(31.6)	2.6	55.1	307
2050	1,877	1,474	1,877	2,567	1,845	1,880	1,932	**2,190**	(403)	0	690.2	(32.1)	2.6	55.3	313

Avg. last 15 yrs	1.5%	0.1%	1.4%	1.5%	1.4%	1.4%	1.5%	-0.3%
Avg. last 10 yrs	1.6%	-0.1%	1.4%	1.6%	1.4%	1.4%	1.6%	-0.7%
Avg. last 5 yrs	2.8%	1.3%	2.9%	2.8%	2.5%	2.4%	2.8%	0.7%
Base 2022								
Avg. next 5 yrs	0.4%	-0.2%	0.8%	0.8%	0.4%	0.8%	0.5%	1.4%
Avg. next 10 yrs	0.8%	0.5%	0.9%	1.7%	0.7%	1.0%	0.8%	2.3%
Avg. next 15 yrs	0.8%	0.6%	0.9%	2.1%	0.7%	0.9%	0.9%	2.8%
Avg. next 20 yrs	0.8%	0.7%	0.9%	2.2%	0.8%	0.9%	0.9%	2.8%
Avg. next 25 yrs	1.7%	1.6%	1.8%	3.8%	1.6%	1.8%	1.9%	4.6%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating Pump Cooling (reduces load)

NEMA
WINTER Peaks **after DER Impacts ***

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 10-90 (MW)	Extreme 10-90 (% Grwth)	Extreme 05-95 (MW)	Extreme 05-95 (% Grwth)	HDD_wtd ACTUAL
2006	946		991		1,033		1,045		45.2
2007	956	1.0%	945	-4.7%	980	-5.1%	990	-5.3%	47.6
2008	908	-5.0%	937	-0.9%	976	-0.5%	987	-0.4%	40.4
2009	918	1.1%	955	2.0%	997	2.2%	1,009	2.3%	37.6
2010	940	2.4%	911	-4.7%	954	-4.4%	966	-4.3%	54.0
2011	865	-8.0%	908	-0.3%	949	-0.5%	961	-0.5%	45.3
2012	906	4.8%	895	-1.4%	931	-1.9%	942	-2.0%	53.6
2013	926	2.2%	898	0.3%	937	0.6%	948	0.7%	54.0
2014	886	-4.4%	874	-2.6%	911	-2.8%	922	-2.8%	52.3
2015	840	-5.2%	833	-4.7%	869	-4.7%	879	-4.6%	57.7
2016	836	-0.5%	835	0.2%	877	0.9%	888	1.1%	46.5
2017	887	6.2%	828	-0.8%	882	0.6%	897	1.0%	57.4
2018	897	1.0%	887	7.1%	936	6.2%	950	5.9%	50.0
2019	791	-11.8%	832	-6.2%	876	-6.4%	889	-6.5%	39.7
2020	818	3.5%	882	6.0%	929	6.0%	942	6.0%	40.1
2021	846	3.4%	844	-4.3%	889	-4.3%	902	-4.2%	45.4
2022	-	-	885	4.9%	935	5.2%	949	5.2%	-
2023		-	903	2.0%	954	2.0%	968	2.0%	
2024		-	921	2.0%	973	2.0%	987	2.0%	
2025	-	-	937	1.8%	990	1.8%	1,005	1.8%	-
2026	-	-	968	3.2%	1,019	2.9%	1,033	2.8%	-
2027	-	-	1,001	3.4%	1,052	3.3%	1,067	3.3%	-
2028	-	-	1,047	4.6%	1,099	4.4%	1,114	4.4%	-
2029	-	-	1,093	4.5%	1,146	4.3%	1,161	4.3%	-
2030	-	-	1,154	5.5%	1,208	5.4%	1,223	5.3%	-
2031	-	-	1,228	6.5%	1,283	6.2%	1,298	6.2%	-
2032	-	-	1,314	7.0%	1,369	6.7%	1,385	6.7%	-
2033	-	-	1,411	7.4%	1,467	7.1%	1,483	7.1%	-
2034	-	-	1,517	7.5%	1,574	7.3%	1,590	7.2%	-
2035	-	-	1,632	7.6%	1,690	7.4%	1,706	7.3%	-
2036	-	-	1,752	7.3%	1,810	7.1%	1,827	7.1%	-
2037	-		1,878	7.2%	1,937	7.0%	1,954	7.0%	-
2038	-		1,990	6.0%	2,050	5.8%	2,067	5.8%	-
2039	-		2,107	5.9%	2,167	5.7%	2,185	5.7%	-
2040	-		2,235	6.0%	2,295	5.9%	2,313	5.9%	-
2041	-		2,331	4.3%	2,393	4.2%	2,410	4.2%	-
2042	-		2,427	4.1%	2,489	4.0%	2,507	4.0%	-
2043	-		2,514	3.6%	2,578	3.6%	2,597	3.6%	-
2044	-		2,598	3.3%	2,664	3.3%	2,683	3.3%	-
2045	-		2,669	2.7%	2,736	2.7%	2,754	2.7%	-
2046	-		2,732	2.4%	2,799	2.3%	2,818	2.3%	-
2047	-		2,793	2.2%	2,861	2.2%	2,880	2.2%	-
2048	-		2,853	2.1%	2,921	2.1%	2,941	2.1%	-
2049	-		2,884	1.1%	2,953	1.1%	2,972	1.1%	-
2050	-		2,903	0.7%	2,972	0.6%	2,992	0.6%	-

	Normal 50-50	Extreme 10-90	Extreme 05-95
Avg. last 15 yrs	-1.1%	-1.0%	-1.0%
Avg. last 10 yrs	-0.7%	-0.7%	-0.6%
Avg. last 5 yrs	0.2%	0.3%	0.3%
Base 2021			
Avg. next 5 yrs	2.8%	2.8%	2.8%
Avg. next 10 yrs	3.8%	3.7%	3.7%
Avg. next 15 yrs	5.0%	4.9%	4.8%
Avg. next 20 yrs	5.2%	5.1%	5.0%
Avg. next 25 yrs	4.8%	4.7%	4.7%

HDD_wtd

NORMAL	47.7
EXTREME 90/10	56.5
EXTREME 95/5	59.0

**** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response (solar and demand response are zero at times of winter peak)***

NEMA	WINTER 50/50 Peaks (MW) (before & after DERs)														
	SYSTEM PEAK								DER IMPACTS						
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2006	1,035	991	1,035	1,035	1,035	1,035	1,035	**991**	(44)	0	0.0	0.0	0.0	0.0	(44)
2007	1,003	945	1,003	1,003	1,003	1,003	1,003	**945**	(58)	0	0.0	0.0	0.0	0.0	(58)
2008	1,003	937	1,003	1,003	1,003	1,003	1,003	**937**	(66)	0	0.0	0.0	0.0	0.0	(66)
2009	1,037	955	1,037	1,037	1,037	1,037	1,037	**955**	(82)	0	0.0	0.0	0.0	0.0	(82)
2010	1,007	911	1,007	1,007	1,007	1,007	1,007	**911**	(96)	0	0.0	0.0	0.0	0.0	(96)
2011	1,018	908	1,018	1,018	1,018	1,018	1,018	**908**	(110)	0	0.0	0.0	0.0	0.0	(110)
2012	1,021	895	1,021	1,021	1,021	1,021	1,021	**895**	(126)	0	0.1	0.0	0.0	0.0	(126)
2013	1,045	898	1,045	1,045	1,045	1,045	1,045	**898**	(148)	0	0.1	0.0	0.0	0.0	(147)
2014	1,045	874	1,045	1,045	1,045	1,045	1,045	**874**	(171)	0	0.3	0.0	0.0	0.0	(171)
2015	1,030	833	1,030	1,030	1,030	1,030	1,030	**833**	(197)	0	0.5	0.0	0.0	0.0	(197)
2016	1,058	835	1,058	1,059	1,058	1,058	1,058	**835**	(224)	0	0.5	0.0	0.0	0.0	(223)
2017	1,079	827	1,079	1,080	1,079	1,079	1,079	**828**	(251)	0	0.8	0.0	(0.1)	0.0	(251)
2018	1,168	886	1,168	1,169	1,168	1,167	1,168	**887**	(282)	0	1.3	0.0	(0.4)	0.0	(281)
2019	1,146	834	1,146	1,148	1,146	1,141	1,146	**832**	(312)	0	1.8	0.0	(4.5)	0.2	(314)
2020	1,231	889	1,231	1,233	1,231	1,221	1,231	**882**	(342)	0	2.3	0.0	(10.3)	0.5	(349)
2021	1,221	861	1,221	1,225	1,221	1,200	1,222	**844**	(361)	0	3.4	0.0	(21.5)	1.0	(378)
2022	1,281	910	1,281	1,286	1,281	1,248	1,283	**885**	(371)	0	5.5	0.0	(32.7)	2.4	(396)
2023	1,312	932	1,312	1,322	1,312	1,268	1,317	**903**	(380)	0	9.2	0.0	(43.9)	5.0	(410)
2024	1,341	953	1,341	1,355	1,341	1,286	1,350	**921**	(388)	0	14.5	0.0	(55.2)	8.6	(420)
2025	1,363	968	1,363	1,385	1,363	1,299	1,376	**937**	(396)	0	21.3	0.0	(64.1)	12.2	(426)
2026	1,312	911	1,312	1,353	1,312	1,314	1,327	**968**	(402)	0	40.5	0.0	2.0	14.5	(345)
2027	1,329	923	1,329	1,386	1,329	1,332	1,349	**1,001**	(407)	0	56.9	0.0	2.1	19.0	(329)
2028	1,353	942	1,353	1,431	1,353	1,355	1,377	**1,047**	(411)	0	78.3	0.0	2.3	24.0	(307)
2029	1,368	953	1,368	1,476	1,368	1,371	1,398	**1,093**	(415)	0	108.1	0.0	2.4	29.4	(275)
2030	1,389	971	1,389	1,534	1,389	1,391	1,424	**1,154**	(418)	0	145.4	0.0	2.4	35.1	(235)
2031	1,409	988	1,409	1,602	1,409	1,412	1,453	**1,228**	(421)	0	193.2	0.0	2.5	44.3	(181)
2032	1,429	1,006	1,429	1,675	1,429	1,432	1,489	**1,314**	(423)	0	245.4	0.0	2.6	60.0	(115)
2033	1,449	1,024	1,449	1,752	1,449	1,452	1,531	**1,411**	(425)	0	302.4	0.0	2.6	81.8	(38)
2034	1,468	1,042	1,468	1,832	1,468	1,471	1,578	**1,517**	(427)	0	363.3	0.0	2.6	109.2	48
2035	1,490	1,061	1,490	1,916	1,490	1,492	1,631	**1,632**	(428)	0	426.7	0.0	2.7	141.4	143
2036	1,511	1,081	1,511	2,001	1,511	1,513	1,688	**1,752**	(430)	0	490.4	0.0	2.7	177.7	241
2037	1,537	1,106	1,537	2,089	1,537	1,539	1,754	**1,878**	(431)	0	552.6	0.0	2.7	217.2	342
2038	1,548	1,116	1,548	2,161	1,548	1,551	1,807	**1,990**	(432)	0	612.7	0.0	2.7	258.9	442
2039	1,562	1,128	1,562	2,237	1,562	1,565	1,864	**2,107**	(434)	0	674.5	0.0	2.7	301.7	545
2040	1,580	1,145	1,580	2,322	1,580	1,583	1,925	**2,235**	(435)	0	741.8	0.0	2.7	344.7	654
2041	1,596	1,159	1,596	2,378	1,596	1,599	1,983	**2,331**	(437)	0	782.3	0.0	2.7	386.9	735
2042	1,616	1,178	1,616	2,435	1,616	1,619	2,043	**2,427**	(438)	0	819.0	0.0	2.8	427.3	811
2043	1,634	1,195	1,634	2,486	1,634	1,637	2,100	**2,514**	(439)	0	851.6	0.0	2.8	465.0	880
2044	1,708	1,267	1,708	2,568	1,708	1,608	2,278	**2,598**	(441)	0	860.4	0.0	(99.7)	570.7	891
2045	1,722	1,279	1,722	2,606	1,722	1,622	2,327	**2,669**	(442)	0	884.9	0.0	(99.9)	605.2	948
2046	1,736	1,292	1,736	2,642	1,736	1,636	2,370	**2,732**	(444)	0	906.0	0.0	(99.9)	634.2	997
2047	1,757	1,312	1,757	2,681	1,757	1,657	2,414	**2,793**	(445)	0	923.9	0.0	(99.9)	657.4	1,036
2048	1,786	1,339	1,786	2,725	1,786	1,686	2,460	**2,853**	(447)	0	939.2	0.0	(99.9)	674.2	1,067
2049	1,795	1,347	1,795	2,747	1,795	1,695	2,480	**2,884**	(448)	0	952.2	0.0	(99.9)	684.4	1,089
2050	1,801	1,352	1,801	2,764	1,801	1,701	2,489	**2,903**	(449)	0	963.4	0.0	(99.9)	687.8	1,102

	-							
Avg. last 15 yrs	1.1%	-0.9%	1.1%	1.1%	1.1%	1.0%	1.1%	-1.1%
Avg. last 10 yrs	1.8%	-0.5%	1.8%	1.9%	1.8%	1.7%	1.8%	-0.7%
Avg. last 5 yrs	2.9%	0.6%	2.9%	3.0%	2.9%	2.5%	2.9%	0.2%
Base 2021								
Avg. next 5 yrs	1.4%	1.1%	1.4%	2.0%	1.4%	1.8%	1.7%	2.8%
Avg. next 10 yrs	1.4%	1.4%	1.4%	2.7%	1.4%	1.6%	1.7%	3.8%
Avg. next 15 yrs	1.4%	1.5%	1.4%	3.3%	1.4%	1.6%	2.2%	5.0%
Avg. next 20 yrs	1.3%	1.5%	1.3%	3.4%	1.3%	1.4%	2.4%	5.2%
Avg. next 25 yrs	1.4%	1.6%	1.4%	3.1%	1.4%	1.2%	2.7%	4.8%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating/Cooling (ADDs to load)

SEMA Zone (Southeast Massachusetts)

SEMA
Annual Peaks

AFTER DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	Peak Season (50-50)
2006	1,705		1,575		1,695		1,729		S
2007	1,522	-10.7%	1,589	0.9%	1,703	0.5%	1,735	0.4%	S
2008	1,549	1.8%	1,574	-0.9%	1,688	-0.9%	1,720	-0.9%	S
2009	1,456	-6.0%	1,588	0.9%	1,708	1.2%	1,742	1.3%	S
2010	1,586	8.9%	1,584	-0.3%	1,711	0.2%	1,747	0.3%	S
2011	1,658	4.5%	1,581	-0.2%	1,701	-0.6%	1,734	-0.7%	S
2012	1,551	-6.5%	1,587	0.4%	1,695	-0.3%	1,726	-0.5%	S
2013	1,659	7.0%	1,570	-1.1%	1,688	-0.4%	1,722	-0.2%	S
2014	1,417	-14.6%	1,585	0.9%	1,707	1.1%	1,742	1.2%	S
2015	1,473	4.0%	1,566	-1.1%	1,691	-1.0%	1,726	-0.9%	S
2016	1,519	3.1%	1,536	-2.0%	1,658	-1.9%	1,692	-1.9%	S
2017	1,419	-6.6%	1,523	-0.8%	1,645	-0.8%	1,679	-0.8%	S
2018	1,549	9.1%	1,494	-1.9%	1,613	-1.9%	1,647	-1.9%	S
2019	1,446	-6.6%	1,451	-2.8%	1,567	-2.9%	1,600	-2.9%	S
2020	1,506	4.1%	1,528	5.3%	1,651	5.4%	1,686	5.4%	S
2021	1,549	2.9%	1,454	-4.8%	1,591	-3.7%	1,629	-3.4%	S
2022	1,538	-0.7%	1,440	-1.0%	1,572	-1.1%	1,610	-1.2%	S
2023	-	-	1,427	-0.9%	1,560	-0.8%	1,598	-0.7%	S
2024	-	-	1,448	1.5%	1,587	1.7%	1,626	1.8%	S
2025	-	-	1,464	1.1%	1,604	1.1%	1,643	1.0%	S
2026	-	-	1,469	0.3%	1,609	0.3%	1,649	0.3%	S
2027	-	-	1,489	1.4%	1,631	1.3%	1,671	1.3%	S
2028	-	-	1,504	1.0%	1,647	1.0%	1,687	1.0%	S
2029	-	-	1,525	1.4%	1,663	1.0%	1,703	1.0%	S
2030	-	-	1,562	2.4%	1,698	2.1%	1,736	1.9%	S
2031	-	-	1,606	2.9%	1,743	2.7%	1,782	2.6%	S
2032	-	-	1,657	3.2%	1,795	3.0%	1,833	2.9%	S
2033	-	-	1,713	3.4%	1,851	3.1%	1,890	3.1%	S
2034	-	-	1,771	3.4%	1,910	3.2%	1,950	3.1%	S
2035	-	-	1,824	2.9%	1,963	2.8%	2,002	2.7%	S
2036	-	-	1,949	6.9%	2,031	3.5%	2,071	3.4%	W
2037	-	-	2,086	7.0%	2,140	5.4%	2,155	4.1%	W
2038	-		2,208	5.9%	2,263	5.7%	2,278	5.7%	W
2039	-		2,336	5.8%	2,391	5.7%	2,407	5.7%	W
2040	-		2,475	5.9%	2,530	5.8%	2,546	5.8%	W
2041	-		2,584	4.4%	2,640	4.3%	2,656	4.3%	W
2042	-		2,692	4.2%	2,749	4.1%	2,766	4.2%	W
2043	-		2,798	3.9%	2,857	3.9%	2,873	3.9%	W
2044	-		2,895	3.5%	2,955	3.4%	2,972	3.4%	W
2045	-		2,978	2.8%	3,038	2.8%	3,055	2.8%	W
2046	-		3,050	2.4%	3,110	2.4%	3,128	2.4%	W
2047	-		3,119	2.3%	3,180	2.2%	3,198	2.2%	W
2048	-		3,186	2.1%	3,248	2.1%	3,265	2.1%	W
2049	-		3,220	1.1%	3,282	1.1%	3,300	1.1%	W
2050	-		3,239	0.6%	3,302	0.6%	3,319	0.6%	W

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.7%	-0.5%	-0.5%
Avg. last 10 yrs	-1.0%	-0.7%	-0.7%
Avg. last 5 yrs	-1.1%	-0.9%	-0.8%
Base 2022			
Avg. next 5 yrs	0.7%	0.7%	0.7%
Avg. next 10 yrs	1.4%	1.3%	1.3%
Avg. next 15 yrs	2.5%	2.1%	2.0%
Avg. next 20 yrs	3.2%	2.8%	2.7%
Avg. next 25 yrs	3.1%	2.9%	2.8%

**** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heat pumps, and company demand response***

SEMA
SUMMER Peaks **AFTER DER Impacts ***

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	WTHI ACTUAL
2006	1,705		1,575		1,695		1,729		84.9
2007	1,522	-10.7%	1,589	0.9%	1,703	0.5%	1,735	0.4%	81.1
2008	1,549	1.8%	1,574	-0.9%	1,688	-0.9%	1,720	-0.9%	82.5
2009	1,456	-6.0%	1,588	0.9%	1,708	1.2%	1,742	1.3%	80.5
2010	1,586	8.9%	1,584	-0.3%	1,711	0.2%	1,747	0.3%	83.4
2011	1,658	4.5%	1,581	-0.2%	1,701	-0.6%	1,734	-0.7%	84.9
2012	1,551	-6.5%	1,587	0.4%	1,695	-0.3%	1,726	-0.5%	81.7
2013	1,659	7.0%	1,570	-1.1%	1,688	-0.4%	1,722	-0.2%	84.2
2014	1,417	-14.6%	1,585	0.9%	1,707	1.1%	1,742	1.2%	80.2
2015	1,473	4.0%	1,566	-1.1%	1,691	-1.0%	1,726	-0.9%	80.0
2016	1,519	3.1%	1,536	-2.0%	1,658	-1.9%	1,692	-1.9%	83.0
2017	1,419	-6.6%	1,523	-0.8%	1,645	-0.8%	1,679	-0.8%	81.9
2018	1,549	9.1%	1,494	-1.9%	1,613	-1.9%	1,647	-1.9%	83.5
2019	1,446	-6.6%	1,451	-2.8%	1,567	-2.9%	1,600	-2.9%	84.1
2020	1,506	4.1%	1,528	5.3%	1,651	5.4%	1,686	5.4%	82.0
2021	1,549	2.9%	1,454	-4.8%	1,591	-3.7%	1,629	-3.4%	84.5
2022	1,538	-0.7%	1,440	-1.0%	1,572	-1.1%	1,610	-1.2%	84.5
2023	-	-	1,427	-0.9%	1,560	-0.8%	1,598	-0.7%	-
2024	-	-	1,448	1.5%	1,587	1.7%	1,626	1.8%	-
2025	-	-	1,464	1.1%	1,604	1.1%	1,643	1.0%	-
2026	-	-	1,469	0.3%	1,609	0.3%	1,649	0.3%	-
2027	-	-	1,489	1.4%	1,631	1.3%	1,671	1.3%	-
2028	-	-	1,504	1.0%	1,647	1.0%	1,687	1.0%	-
2029	-	-	1,525	1.4%	1,663	1.0%	1,703	1.0%	-
2030	-	-	1,562	2.4%	1,698	2.1%	1,736	1.9%	-
2031	-	-	1,606	2.9%	1,743	2.7%	1,782	2.6%	-
2032	-	-	1,657	3.2%	1,795	3.0%	1,833	2.9%	-
2033	-	-	1,713	3.4%	1,851	3.1%	1,890	3.1%	-
2034	-	-	1,771	3.4%	1,910	3.2%	1,950	3.1%	-
2035	-	-	1,824	2.9%	1,963	2.8%	2,002	2.7%	-
2036	-	-	1,891	3.7%	2,031	3.5%	2,071	3.4%	-
2037	-	-	1,938	2.5%	2,079	2.3%	2,118	2.3%	-
2038	-		2,005	3.4%	2,146	3.2%	2,186	3.2%	-
2039	-		2,066	3.1%	2,208	2.9%	2,249	2.9%	-
2040	-		2,136	3.4%	2,279	3.2%	2,319	3.2%	-
2041	-		2,189	2.5%	2,333	2.3%	2,373	2.3%	-
2042	-		2,227	1.8%	2,372	1.7%	2,412	1.7%	-
2043	-		2,263	1.6%	2,407	1.5%	2,448	1.5%	-
2044	-		2,306	1.9%	2,451	1.8%	2,492	1.8%	-
2045	-		2,341	1.5%	2,487	1.5%	2,528	1.4%	-
2046	-		2,386	1.9%	2,533	1.9%	2,575	1.8%	-
2047	-		2,418	1.3%	2,566	1.3%	2,608	1.3%	-
2048	-		2,429	0.5%	2,577	0.4%	2,619	0.4%	-
2049	-		2,472	1.8%	2,621	1.7%	2,664	1.7%	-
2050	-		2,503	1.3%	2,653	1.2%	2,696	1.2%	-

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.7%	-0.5%	-0.5%
Avg. last 10 yrs	-1.0%	-0.7%	-0.7%
Avg. last 5 yrs	-1.1%	-0.9%	-0.8%
Base 2022			
Avg. next 5 yrs	0.7%	0.7%	0.7%
Avg. next 10 yrs	1.4%	1.3%	1.3%
Avg. next 15 yrs	2.0%	1.9%	1.8%
Avg. next 20 yrs	2.2%	2.1%	2.0%
Avg. next 25 yrs	2.1%	2.0%	1.9%

WTHI

NORMAL	82.4
EXTREME 90/10	84.7
EXTREME 95/5	85.4

**** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response***

SEMA	SUMMER 50/50 Peaks (MW) (before & after DERs)															
	SYSTEM PEAK								DER IMPACTS							
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2006	1,608	1,575	1,608	1,608	1,608	1,608	1,608	**1,575**	(33)	(0)	0.0	0.0	0.0	0.0	(33)
2007	1,632	1,589	1,632	1,632	1,632	1,632	1,632	**1,589**	(43)	(0)	0.0	0.0	0.0	0.0	(44)
2008	1,627	1,574	1,627	1,627	1,627	1,627	1,627	**1,574**	(53)	(0)	0.0	0.0	0.0	0.0	(53)
2009	1,655	1,589	1,654	1,655	1,655	1,655	1,655	**1,588**	(65)	(1)	0.0	0.0	0.0	0.0	(66)
2010	1,665	1,584	1,664	1,665	1,665	1,665	1,665	**1,584**	(81)	(1)	0.0	0.0	0.0	0.0	(81)
2011	1,681	1,584	1,678	1,681	1,681	1,681	1,681	**1,581**	(97)	(3)	0.0	0.0	0.0	0.0	(100)
2012	1,711	1,595	1,703	1,711	1,711	1,711	1,711	**1,587**	(116)	(8)	0.0	0.0	0.0	0.0	(124)
2013	1,737	1,598	1,709	1,737	1,737	1,737	1,737	**1,570**	(139)	(28)	0.1	0.0	0.0	0.0	(167)
2014	1,785	1,619	1,751	1,785	1,785	1,785	1,785	**1,585**	(166)	(35)	0.1	0.0	0.0	0.0	(201)
2015	1,775	1,579	1,763	1,776	1,775	1,775	1,775	**1,566**	(196)	(13)	0.2	0.0	0.0	0.0	(209)
2016	1,842	1,611	1,766	1,842	1,842	1,842	1,842	**1,536**	(231)	(76)	0.2	(0.2)	0.0	0.0	(307)
2017	1,858	1,592	1,791	1,858	1,856	1,858	1,858	**1,523**	(266)	(67)	0.4	(2.4)	(0.1)	0.0	(335)
2018	1,839	1,537	1,807	1,840	1,828	1,839	1,839	**1,494**	(302)	(32)	0.8	(11.4)	(0.4)	0.0	(345)
2019	1,849	1,510	1,813	1,850	1,828	1,845	1,849	**1,451**	(339)	(35)	1.1	(20.7)	(3.7)	0.1	(397)
2020	1,971	1,596	1,931	1,972	1,951	1,960	1,971	**1,528**	(374)	(39)	1.5	(19.9)	(10.5)	0.2	(443)
2021	1,943	1,539	1,898	1,945	1,924	1,921	1,944	**1,454**	(404)	(45)	2.1	(19.5)	(22.5)	0.4	(489)
2022	2,178	1,755	1,917	2,180	2,158	2,140	2,179	**1,440**	(423)	(261)	2.3	(19.8)	(37.5)	0.8	(738)
2023	1,993	1,556	1,936	1,998	1,965	1,940	1,994	**1,427**	(436)	(57)	5.5	(27.2)	(52.6)	1.4	(566)
2024	2,090	1,641	1,837	2,095	2,075	2,155	2,092	**1,448**	(448)	(253)	5.8	(14.5)	65.4	2.5	(642)
2025	2,123	1,664	1,847	2,131	2,107	2,201	2,126	**1,464**	(459)	(275)	8.7	(15.4)	78.2	3.7	(659)
2026	2,144	1,676	1,846	2,156	2,128	2,232	2,149	**1,469**	(468)	(297)	12.6	(16.1)	88.4	5.1	(675)
2027	2,180	1,704	1,860	2,197	2,163	2,276	2,187	**1,489**	(475)	(320)	17.8	(16.7)	96.7	7.0	(690)
2028	2,209	1,727	1,866	2,234	2,192	2,312	2,218	**1,504**	(482)	(343)	24.6	(17.5)	103.3	9.2	(705)
2029	2,102	1,614	2,090	2,162	2,065	1,989	2,112	**1,525**	(487)	(12)	60.5	(36.7)	(112.3)	10.5	(577)
2030	2,126	1,634	2,114	2,208	2,088	2,009	2,139	**1,562**	(492)	(12)	82.2	(38.2)	(116.7)	12.8	(564)
2031	2,150	1,654	2,137	2,260	2,111	2,030	2,165	**1,606**	(496)	(13)	109.8	(39.3)	(120.1)	15.5	(543)
2032	2,173	1,674	2,159	2,315	2,133	2,051	2,192	**1,657**	(499)	(14)	141.7	(40.4)	(122.9)	18.8	(516)
2033	2,197	1,695	2,182	2,374	2,156	2,072	2,220	**1,713**	(502)	(15)	176.7	(41.6)	(125.2)	22.8	(484)
2034	2,220	1,715	2,204	2,434	2,177	2,093	2,247	**1,771**	(505)	(16)	214.3	(42.7)	(127.0)	27.4	(449)
2035	2,233	1,726	2,216	2,487	2,189	2,105	2,265	**1,824**	(507)	(17)	254.1	(43.9)	(128.4)	32.3	(409)
2036	2,260	1,751	2,242	2,555	2,214	2,130	2,297	**1,891**	(509)	(18)	294.9	(45.2)	(129.5)	37.6	(369)
2037	2,267	1,756	2,248	2,601	2,220	2,136	2,310	**1,938**	(511)	(19)	334.8	(46.5)	(130.4)	43.0	(328)
2038	2,294	1,782	2,275	2,668	2,246	2,163	2,343	**2,005**	(513)	(19)	373.5	(48.0)	(131.2)	48.5	(289)
2039	2,316	1,801	2,295	2,729	2,266	2,184	2,369	**2,066**	(515)	(20)	413.2	(49.4)	(131.8)	53.8	(249)
2040	2,342	1,826	2,321	2,798	2,292	2,210	2,401	**2,136**	(517)	(22)	456.1	(50.4)	(132.3)	58.8	(206)
2041	2,367	1,849	2,345	2,850	2,316	2,235	2,431	**2,189**	(518)	(23)	482.9	(51.2)	(132.7)	63.6	(178)
2042	2,381	1,861	2,358	2,888	2,329	2,248	2,449	**2,227**	(520)	(23)	507.1	(51.8)	(133.0)	67.9	(154)
2043	2,394	1,872	2,370	2,923	2,342	2,261	2,466	**2,263**	(522)	(24)	528.7	(52.5)	(133.2)	71.7	(132)
2044	2,419	1,895	2,394	2,967	2,366	2,285	2,494	**2,306**	(524)	(25)	547.9	(53.1)	(133.5)	74.9	(113)
2045	2,438	1,912	2,412	3,002	2,384	2,304	2,515	**2,341**	(526)	(25)	564.6	(53.8)	(133.7)	77.7	(97)
2046	2,470	1,942	2,444	3,049	2,415	2,336	2,550	**2,386**	(528)	(26)	579.1	(54.6)	(133.9)	79.9	(84)
2047	2,491	1,961	2,465	3,082	2,436	2,357	2,573	**2,418**	(530)	(26)	591.4	(55.4)	(133.9)	81.6	(73)
2048	2,494	1,962	2,467	3,096	2,437	2,360	2,576	**2,429**	(532)	(27)	602.0	(56.2)	(133.9)	82.8	(64)
2049	2,530	1,996	2,503	3,141	2,473	2,396	2,613	**2,472**	(534)	(27)	610.9	(56.9)	(133.9)	83.6	(57)
2050	2,556	2,020	2,528	3,174	2,498	2,422	2,640	**2,503**	(536)	(27)	618.6	(57.7)	(133.9)	84.0	(52)

Avg. last 15 yrs	1.9%	0.7%	1.1%	1.9%	1.9%	1.8%	1.9%	-0.7%
Avg. last 10 yrs	2.4%	1.0%	1.2%	2.5%	2.3%	2.3%	2.4%	-1.0%
Avg. last 5 yrs	3.2%	2.0%	1.4%	3.2%	3.1%	2.9%	3.2%	-1.1%
Base 2022								
Avg. next 5 yrs	0.0%	-0.6%	-0.6%	0.2%	0.0%	1.2%	0.1%	0.7%
Avg. next 10 yrs	0.0%	-0.5%	1.2%	0.6%	-0.1%	-0.4%	0.1%	1.4%
Avg. next 15 yrs	0.3%	0.0%	1.1%	1.2%	0.2%	0.0%	0.4%	2.0%
Avg. next 20 yrs	0.4%	0.3%	1.0%	1.4%	0.4%	0.2%	0.6%	2.2%
Avg. next 25 yrs	0.5%	0.4%	1.0%	1.4%	0.5%	0.4%	0.7%	2.1%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating Pump Cooling (reduces load)

SEMA
WINTER Peaks

after DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 10-90 (MW)	Extreme 10-90 (% Grwth)	Extreme 05-95 (MW)	Extreme 05-95 (% Grwth)	HDD_wtd ACTUAL
2006	1,194		1,193		1,230		1,240		46.9
2007	1,181	-1.1%	1,165	-2.4%	1,200	-2.4%	1,209	-2.5%	46.7
2008	1,138	-3.7%	1,134	-2.6%	1,172	-2.3%	1,182	-2.2%	47.3
2009	1,143	0.4%	1,182	4.2%	1,223	4.3%	1,234	4.4%	36.7
2010	1,151	0.8%	1,109	-6.2%	1,150	-5.9%	1,162	-5.8%	54.9
2011	1,084	-5.8%	1,118	0.8%	1,158	0.7%	1,169	0.6%	45.4
2012	1,165	7.4%	1,147	2.6%	1,184	2.3%	1,195	2.2%	49.8
2013	1,218	4.6%	1,228	7.1%	1,269	7.2%	1,281	7.2%	44.4
2014	1,132	-7.0%	1,112	-9.5%	1,150	-9.4%	1,160	-9.4%	52.4
2015	1,058	-6.6%	1,082	-2.7%	1,118	-2.8%	1,128	-2.8%	42.3
2016	1,100	4.0%	1,095	1.2%	1,141	2.1%	1,154	2.3%	46.0
2017	1,155	4.9%	1,108	1.2%	1,162	1.9%	1,178	2.1%	52.6
2018	1,138	-1.4%	1,107	0.0%	1,153	-0.8%	1,166	-1.0%	51.3
2019	1,016	-10.7%	1,043	-5.8%	1,085	-5.8%	1,097	-5.8%	41.7
2020	1,042	2.5%	1,102	5.6%	1,147	5.7%	1,160	5.7%	39.7
2021	1,061	1.9%	1,053	-4.4%	1,095	-4.5%	1,107	-4.6%	45.1
2022	-	-	1,075	2.1%	1,122	2.5%	1,136	2.6%	-
2023		-	1,081	0.5%	1,129	0.6%	1,143	0.6%	
2024		-	1,096	1.4%	1,145	1.4%	1,159	1.4%	
2025	-	-	1,110	1.3%	1,160	1.3%	1,174	1.3%	-
2026	-	-	1,135	2.2%	1,186	2.2%	1,200	2.2%	-
2027	-	-	1,166	2.7%	1,214	2.4%	1,227	2.3%	-
2028	-	-	1,213	4.0%	1,261	3.9%	1,275	3.9%	-
2029	-	-	1,260	3.8%	1,308	3.7%	1,322	3.7%	-
2030	-	-	1,320	4.8%	1,370	4.7%	1,384	4.6%	-
2031	-	-	1,395	5.7%	1,445	5.5%	1,459	5.5%	-
2032	-	-	1,483	6.3%	1,534	6.1%	1,548	6.1%	-
2033	-	-	1,585	6.8%	1,636	6.6%	1,651	6.6%	-
2034	-	-	1,697	7.1%	1,749	6.9%	1,763	6.8%	-
2035	-	-	1,820	7.3%	1,872	7.1%	1,887	7.0%	-
2036	-	-	1,949	7.1%	2,002	6.9%	2,017	6.9%	-
2037	-		2,086	7.0%	2,140	6.9%	2,155	6.8%	-
2038	-		2,208	5.9%	2,263	5.7%	2,278	5.7%	-
2039	-		2,336	5.8%	2,391	5.7%	2,407	5.7%	-
2040	-		2,475	5.9%	2,530	5.8%	2,546	5.8%	-
2041	-		2,584	4.4%	2,640	4.3%	2,656	4.3%	-
2042	-		2,692	4.2%	2,749	4.1%	2,766	4.2%	-
2043	-		2,798	3.9%	2,857	3.9%	2,873	3.9%	-
2044	-		2,895	3.5%	2,955	3.4%	2,972	3.4%	-
2045	-		2,978	2.8%	3,038	2.8%	3,055	2.8%	-
2046	-		3,050	2.4%	3,110	2.4%	3,128	2.4%	-
2047	-		3,119	2.3%	3,180	2.2%	3,198	2.2%	-
2048	-		3,186	2.1%	3,248	2.1%	3,265	2.1%	-
2049	-		3,220	1.1%	3,282	1.1%	3,300	1.1%	-
2050	-		3,239	0.6%	3,302	0.6%	3,319	0.6%	-

	Normal 50-50	Extreme 10-90	Extreme 05-95
Avg. last 15 yrs	-0.8%	-0.8%	-0.8%
Avg. last 10 yrs	-0.6%	-0.6%	-0.5%
Avg. last 5 yrs	-0.8%	-0.8%	-0.8%
Base 2021			
Avg. next 5 yrs	1.5%	1.6%	1.6%
Avg. next 10 yrs	2.9%	2.8%	2.8%
Avg. next 15 yrs	4.2%	4.1%	4.1%
Avg. next 20 yrs	4.6%	4.5%	4.5%
Avg. next 25 yrs	4.3%	4.3%	4.2%

HDD_wtd

NORMAL	46.3
EXTREME 90/10	53.6
EXTREME 95/5	55.7

** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response*

SEMA — WINTER 50/50 Peaks (MW) (before & after DERs)

Calendar Year	SYSTEM PEAK: Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	DER IMPACTS: EE	PV	EV	DR	ES	EH	DER
2006	1,249	1,193	1,249	1,249	1,249	1,249	1,249	**1,193**	(56)	0	0.0	0.0	0.0	0.0	(56)
2007	1,238	1,165	1,238	1,238	1,238	1,238	1,238	**1,165**	(73)	0	0.0	0.0	0.0	0.0	(73)
2008	1,218	1,134	1,218	1,218	1,218	1,218	1,218	**1,134**	(84)	0	0.0	0.0	0.0	0.0	(84)
2009	1,285	1,182	1,285	1,285	1,285	1,285	1,285	**1,182**	(103)	0	0.0	0.0	0.0	0.0	(103)
2010	1,229	1,109	1,229	1,229	1,229	1,229	1,229	**1,109**	(120)	0	0.0	0.0	0.0	0.0	(120)
2011	1,257	1,118	1,257	1,257	1,257	1,257	1,257	**1,118**	(139)	0	0.0	0.0	0.0	0.0	(139)
2012	1,306	1,147	1,306	1,306	1,306	1,306	1,306	**1,147**	(159)	0	0.1	0.0	0.0	0.0	(159)
2013	1,416	1,228	1,416	1,416	1,416	1,416	1,416	**1,228**	(188)	0	0.1	0.0	0.0	0.0	(187)
2014	1,330	1,112	1,330	1,330	1,330	1,330	1,330	**1,112**	(218)	0	0.3	0.0	0.0	0.0	(217)
2015	1,333	1,082	1,333	1,333	1,333	1,333	1,333	**1,082**	(251)	0	0.4	0.0	0.0	0.0	(251)
2016	1,381	1,094	1,381	1,381	1,381	1,381	1,381	**1,095**	(286)	0	0.5	0.0	0.0	0.0	(286)
2017	1,429	1,107	1,429	1,430	1,429	1,429	1,429	**1,108**	(322)	0	0.8	0.0	(0.1)	0.0	(321)
2018	1,467	1,107	1,467	1,469	1,467	1,467	1,467	**1,107**	(361)	0	1.1	0.0	(0.6)	0.0	(360)
2019	1,446	1,047	1,446	1,447	1,446	1,440	1,446	**1,043**	(399)	0	1.9	0.0	(6.0)	0.2	(403)
2020	1,550	1,113	1,550	1,552	1,550	1,536	1,551	**1,102**	(437)	0	2.0	0.0	(13.8)	0.7	(448)
2021	1,539	1,078	1,539	1,542	1,539	1,510	1,540	**1,053**	(461)	0	3.0	0.0	(29.0)	1.4	(486)
2022	1,585	1,111	1,585	1,590	1,585	1,541	1,588	**1,075**	(474)	0	4.9	0.0	(44.2)	3.2	(510)
2023	1,610	1,125	1,610	1,619	1,610	1,551	1,617	**1,081**	(485)	0	8.4	0.0	(59.3)	6.8	(530)
2024	1,642	1,146	1,642	1,655	1,642	1,567	1,653	**1,096**	(496)	0	13.2	0.0	(74.5)	11.6	(546)
2025	1,666	1,161	1,666	1,686	1,666	1,580	1,683	**1,110**	(505)	0	19.5	0.0	(86.5)	16.5	(556)
2026	1,694	1,181	1,694	1,722	1,694	1,598	1,717	**1,135**	(513)	0	28.0	0.0	(96.1)	22.4	(559)
2027	1,605	1,085	1,605	1,657	1,605	1,608	1,631	**1,166**	(520)	0	52.3	0.0	2.9	25.7	(439)
2028	1,631	1,105	1,631	1,703	1,631	1,634	1,663	**1,213**	(525)	0	72.0	0.0	3.1	32.4	(418)
2029	1,647	1,117	1,647	1,747	1,647	1,650	1,687	**1,260**	(530)	0	99.4	0.0	3.2	39.7	(388)
2030	1,670	1,136	1,670	1,804	1,670	1,673	1,717	**1,320**	(534)	0	133.8	0.0	3.3	47.4	(349)
2031	1,692	1,154	1,692	1,869	1,692	1,695	1,751	**1,395**	(537)	0	177.9	0.0	3.4	59.8	(296)
2032	1,713	1,173	1,713	1,939	1,713	1,717	1,794	**1,483**	(540)	0	226.0	0.0	3.5	80.9	(230)
2033	1,735	1,192	1,735	2,014	1,735	1,739	1,845	**1,585**	(543)	0	278.6	0.0	3.5	110.4	(150)
2034	1,756	1,211	1,756	2,091	1,756	1,760	1,903	**1,697**	(545)	0	334.8	0.0	3.6	147.3	(59)
2035	1,779	1,232	1,779	2,172	1,779	1,783	1,970	**1,820**	(547)	0	393.2	0.0	3.6	190.9	41
2036	1,802	1,254	1,802	2,254	1,802	1,806	2,042	**1,949**	(549)	0	451.9	0.0	3.6	239.9	147
2037	1,830	1,280	1,830	2,339	1,830	1,834	2,123	**2,086**	(550)	0	509.3	0.0	3.7	293.1	256
2038	1,843	1,291	1,843	2,407	1,843	1,846	2,192	**2,208**	(552)	0	564.7	0.0	3.7	349.4	366
2039	1,858	1,304	1,858	2,480	1,858	1,862	2,265	**2,336**	(554)	0	621.6	0.0	3.7	407.2	479
2040	1,878	1,322	1,878	2,562	1,878	1,882	2,343	**2,475**	(556)	0	683.7	0.0	3.7	465.2	597
2041	1,895	1,337	1,895	2,616	1,895	1,899	2,417	**2,584**	(558)	0	721.0	0.0	3.7	522.1	689
2042	1,917	1,357	1,917	2,671	1,917	1,920	2,493	**2,692**	(559)	0	754.8	0.0	3.7	576.7	776
2043	2,009	1,448	2,009	2,776	2,009	1,874	2,726	**2,798**	(561)	0	767.1	0.0	(134.3)	717.3	789
2044	2,030	1,467	2,030	2,823	2,030	1,895	2,800	**2,895**	(563)	0	793.0	0.0	(134.5)	770.2	866
2045	2,045	1,480	2,045	2,860	2,045	1,910	2,862	**2,978**	(565)	0	815.6	0.0	(134.8)	816.7	933
2046	2,060	1,494	2,060	2,895	2,060	1,926	2,916	**3,050**	(567)	0	835.0	0.0	(134.8)	856.0	990
2047	2,084	1,515	2,084	2,935	2,084	1,949	2,971	**3,119**	(568)	0	851.6	0.0	(134.8)	887.2	1,036
2048	2,115	1,545	2,115	2,981	2,115	1,980	3,025	**3,186**	(570)	0	865.7	0.0	(134.8)	909.9	1,071
2049	2,125	1,553	2,125	3,003	2,125	1,990	3,049	**3,220**	(572)	0	877.7	0.0	(134.8)	923.7	1,095
2050	2,132	1,558	2,132	3,020	2,132	1,997	3,060	**3,239**	(574)	0	887.9	0.0	(134.8)	928.3	1,108

	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)
	-							
Avg. last 15 yrs	1.4%	-0.7%	1.4%	1.4%	1.4%	1.3%	1.4%	-0.8%
Avg. last 10 yrs	2.0%	-0.4%	2.0%	2.1%	2.0%	1.9%	2.1%	-0.6%
Avg. last 5 yrs	2.2%	-0.3%	2.2%	2.2%	2.2%	1.8%	2.2%	-0.8%
Base 2021								
Avg. next 5 yrs	1.9%	1.9%	1.9%	2.2%	1.9%	1.1%	2.2%	1.5%
Avg. next 10 yrs	1.0%	0.7%	1.0%	1.9%	1.0%	1.2%	1.3%	2.9%
Avg. next 15 yrs	1.1%	1.0%	1.1%	2.6%	1.1%	1.2%	1.9%	4.2%
Avg. next 20 yrs	0.8%	0.8%	0.8%	1.9%	0.8%	0.9%	1.4%	3.1%
Avg. next 25 yrs	1.2%	1.3%	1.2%	2.6%	1.2%	1.0%	2.6%	4.3%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating/Cooling (ADDs to load)

WCMA Zone (Western/Central Massachusetts)

WCMA

Annual Peaks **AFTER DER Impacts ***

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	Peak Season (50-50)
2006	2,229		2,092		2,197		2,226		S
2007	2,088	-6.3%	2,104	0.5%	2,206	0.4%	2,235	0.4%	S
2008	2,167	3.8%	2,107	0.2%	2,204	-0.1%	2,232	-0.1%	S
2009	1,984	-8.4%	2,064	-2.0%	2,161	-1.9%	2,189	-1.9%	S
2010	2,137	7.7%	2,089	1.2%	2,192	1.4%	2,221	1.5%	S
2011	2,182	2.1%	2,112	1.1%	2,212	0.9%	2,240	0.9%	S
2012	2,073	-5.0%	2,078	-1.6%	2,178	-1.5%	2,207	-1.5%	S
2013	2,165	4.5%	2,059	-0.9%	2,161	-0.8%	2,190	-0.8%	S
2014	1,935	-10.6%	2,049	-0.5%	2,154	-0.3%	2,184	-0.3%	S
2015	1,935	0.0%	2,034	-0.7%	2,139	-0.7%	2,168	-0.7%	S
2016	1,983	2.4%	2,029	-0.3%	2,129	-0.5%	2,157	-0.5%	S
2017	1,879	-5.2%	1,998	-1.5%	2,117	-0.5%	2,151	-0.3%	S
2018	2,026	7.8%	1,986	-0.6%	2,086	-1.5%	2,115	-1.7%	S
2019	1,882	-7.1%	1,929	-2.9%	2,025	-2.9%	2,053	-2.9%	S
2020	1,904	1.2%	1,946	0.9%	2,060	1.7%	2,092	1.9%	S
2021	1,978	3.9%	1,925	-1.0%	2,021	-1.9%	2,048	-2.1%	S
2022	2,006	1.4%	1,960	1.8%	2,070	2.4%	2,101	2.6%	S
2023	-	-	1,967	0.4%	2,070	0.0%	2,099	-0.1%	S
2024	-	-	1,992	1.3%	2,095	1.2%	2,124	1.2%	S
2025	-	-	2,023	1.5%	2,125	1.5%	2,155	1.5%	S
2026	-	-	2,045	1.1%	2,148	1.1%	2,177	1.1%	S
2027	-	-	2,090	2.2%	2,193	2.1%	2,222	2.1%	S
2028	-	-	2,133	2.1%	2,237	2.0%	2,266	2.0%	S
2029	-	-	2,183	2.3%	2,287	2.2%	2,316	2.2%	S
2030	-	-	2,239	2.6%	2,343	2.5%	2,372	2.4%	S
2031	-	-	2,305	2.9%	2,409	2.8%	2,438	2.8%	S
2032	-	-	2,378	3.2%	2,482	3.1%	2,512	3.0%	S
2033	-	-	2,458	3.3%	2,562	3.2%	2,592	3.2%	S
2034	-	-	2,541	3.4%	2,645	3.2%	2,675	3.2%	S
2035	-	-	2,617	3.0%	2,721	2.9%	2,751	2.8%	S
2036	-	-	2,754	5.2%	2,830	4.0%	2,851	3.7%	W
2037	-	-	2,939	6.7%	3,016	6.6%	3,038	6.5%	W
2038	-	-	3,105	5.7%	3,183	5.5%	3,205	5.5%	W
2039	-	-	3,279	5.6%	3,358	5.5%	3,380	5.5%	W
2040	-	-	3,467	5.7%	3,546	5.6%	3,569	5.6%	W
2041	-	-	3,614	4.2%	3,694	4.2%	3,717	4.2%	W
2042	-	-	3,759	4.0%	3,840	4.0%	3,863	3.9%	W
2043	-	-	3,892	3.5%	3,974	3.5%	3,998	3.5%	W
2044	-	-	4,021	3.3%	4,105	3.3%	4,129	3.3%	W
2045	-	-	4,130	2.7%	4,216	2.7%	4,240	2.7%	W
2046	-	-	4,227	2.3%	4,313	2.3%	4,337	2.3%	W
2047	-	-	4,319	2.2%	4,406	2.1%	4,430	2.1%	W
2048	-	-	4,406	2.0%	4,494	2.0%	4,519	2.0%	W
2049	-	-	4,451	1.0%	4,540	1.0%	4,565	1.0%	W
2050	-	-	4,477	0.6%	4,567	0.6%	4,592	0.6%	W

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.5%	-0.4%	-0.4%
Avg. last 10 yrs	-0.6%	-0.5%	-0.5%
Avg. last 5 yrs	-0.4%	-0.4%	-0.5%
BASE 2022			
Avg. next 5 yrs	1.3%	1.2%	1.1%
Avg. next 10 yrs	2.0%	1.8%	1.8%
Avg. next 15 yrs	2.7%	2.5%	2.5%
Avg. next 20 yrs	3.3%	3.1%	3.1%
Avg. next 25 yrs	3.2%	3.1%	3.0%

**** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heat pumps, and company demand response***

WCMA
SUMMER Peaks

AFTER DER Impacts *

YEAR	Actuals (MW)	(% Grwth)	Normal 50-50 (MW)	(% Grwth)	Extreme 90-10 (MW)	(% Grwth)	Extreme 95-5 (MW)	(% Grwth)	WTHI ACTUAL
2006	2,229		2,092		2,197		2,226		82.7
2007	2,088	-6.3%	2,104	0.5%	2,206	0.4%	2,235	0.4%	80.7
2008	2,167	3.8%	2,107	0.2%	2,204	-0.1%	2,232	-0.1%	81.6
2009	1,984	-8.4%	2,064	-2.0%	2,161	-1.9%	2,189	-1.9%	79.2
2010	2,137	7.7%	2,089	1.2%	2,192	1.4%	2,221	1.5%	81.3
2011	2,182	2.1%	2,112	1.1%	2,212	0.9%	2,240	0.9%	82.5
2012	2,073	-5.0%	2,078	-1.6%	2,178	-1.5%	2,207	-1.5%	80.5
2013	2,165	4.5%	2,059	-0.9%	2,161	-0.8%	2,190	-0.8%	82.3
2014	1,935	-10.6%	2,049	-0.5%	2,154	-0.3%	2,184	-0.3%	79.5
2015	1,935	0.0%	2,034	-0.7%	2,139	-0.7%	2,168	-0.7%	79.4
2016	1,983	2.4%	2,029	-0.3%	2,129	-0.5%	2,157	-0.5%	80.5
2017	1,879	-5.2%	1,998	-1.5%	2,117	-0.5%	2,151	-0.3%	79.4
2018	2,026	7.8%	1,986	-0.6%	2,086	-1.5%	2,115	-1.7%	81.2
2019	1,882	-7.1%	1,929	-2.9%	2,025	-2.9%	2,053	-2.9%	79.8
2020	1,904	1.2%	1,946	0.9%	2,060	1.7%	2,092	1.9%	80.0
2021	1,978	3.9%	1,925	-1.0%	2,021	-1.9%	2,048	-2.1%	82.1
2022	2,006	1.4%	1,960	1.8%	2,070	2.4%	2,101	2.6%	80.0
2023	-	-	1,967	0.4%	2,070	0.0%	2,099	-0.1%	-
2024	-	-	1,992	1.3%	2,095	1.2%	2,124	1.2%	-
2025	-	-	2,023	1.5%	2,125	1.5%	2,155	1.5%	-
2026	-	-	2,045	1.1%	2,148	1.1%	2,177	1.1%	-
2027	-	-	2,090	2.2%	2,193	2.1%	2,222	2.1%	-
2028	-	-	2,133	2.1%	2,237	2.0%	2,266	2.0%	-
2029	-	-	2,183	2.3%	2,287	2.2%	2,316	2.2%	-
2030	-	-	2,239	2.6%	2,343	2.5%	2,372	2.4%	-
2031	-	-	2,305	2.9%	2,409	2.8%	2,438	2.8%	-
2032	-	-	2,378	3.2%	2,482	3.1%	2,512	3.0%	-
2033	-	-	2,458	3.3%	2,562	3.2%	2,592	3.2%	-
2034	-	-	2,541	3.4%	2,645	3.2%	2,675	3.2%	-
2035	-	-	2,617	3.0%	2,721	2.9%	2,751	2.8%	-
2036	-	-	2,711	3.6%	2,815	3.5%	2,845	3.4%	-
2037	-	-	2,780	2.6%	2,885	2.5%	2,915	2.4%	-
2038	-		2,872	3.3%	2,977	3.2%	3,007	3.2%	-
2039	-		2,958	3.0%	3,063	2.9%	3,093	2.9%	-
2040	-		3,055	3.3%	3,160	3.2%	3,190	3.1%	-
2041	-		3,126	2.3%	3,232	2.3%	3,261	2.2%	-
2042	-		3,180	1.7%	3,285	1.7%	3,315	1.6%	-
2043	-		3,229	1.5%	3,334	1.5%	3,364	1.5%	-
2044	-		3,286	1.8%	3,392	1.7%	3,422	1.7%	-
2045	-		3,333	1.4%	3,439	1.4%	3,469	1.4%	-
2046	-		3,391	1.7%	3,497	1.7%	3,527	1.7%	-
2047	-		3,433	1.2%	3,539	1.2%	3,569	1.2%	-
2048	-		3,449	0.5%	3,555	0.5%	3,585	0.5%	-
2049	-		3,502	1.5%	3,609	1.5%	3,639	1.5%	-
2050	-		3,541	1.1%	3,648	1.1%	3,678	1.1%	-

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.5%	-0.4%	-0.4%
Avg. last 10 yrs	-0.6%	-0.5%	-0.5%
Avg. last 5 yrs	-0.4%	-0.4%	-0.5%
BASE 2022			
Avg. next 5 yrs	1.3%	1.2%	1.1%
Avg. next 10 yrs	2.0%	1.8%	1.8%
Avg. next 15 yrs	2.4%	2.2%	2.2%
Avg. next 20 yrs	1.8%	1.7%	1.6%
Avg. next 25 yrs	2.0%	1.9%	1.8%

WTHI

NORMAL	80.6
EXTREME 90/10	82.2
EXTREME 95/5	82.7

**** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response***

WCMA — SUMMER 50/50 Peaks (MW) (before & after DERs)

Calendar Year	SYSTEM PEAK: Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	DER IMPACTS: EE	PV	EV	DR	ES	EH	DER
2006	2,138	2,092	2,138	2,138	2,138	2,138	2,138	**2,092**	(45)	(0)	0.0	0.0	0.0	0.0	(46)
2007	2,163	2,104	2,162	2,163	2,163	2,163	2,163	**2,104**	(59)	(0)	0.0	0.0	0.0	0.0	(59)
2008	2,180	2,108	2,180	2,180	2,180	2,180	2,180	**2,107**	(73)	(0)	0.0	0.0	0.0	0.0	(73)
2009	2,155	2,066	2,154	2,155	2,155	2,155	2,155	**2,064**	(90)	(1)	0.0	0.0	0.0	0.0	(91)
2010	2,202	2,092	2,199	2,202	2,202	2,202	2,202	**2,089**	(110)	(3)	0.0	0.0	0.0	0.0	(113)
2011	2,252	2,120	2,245	2,252	2,252	2,252	2,252	**2,112**	(132)	(7)	0.0	0.0	0.0	0.0	(140)
2012	2,243	2,086	2,235	2,243	2,243	2,243	2,243	**2,078**	(157)	(8)	0.0	0.0	0.0	0.0	(165)
2013	2,288	2,100	2,247	2,288	2,288	2,288	2,288	**2,059**	(188)	(41)	0.1	0.0	0.0	0.0	(228)
2014	2,355	2,131	2,273	2,356	2,355	2,355	2,355	**2,049**	(224)	(83)	0.2	0.0	0.0	0.0	(306)
2015	2,362	2,098	2,297	2,362	2,362	2,362	2,362	**2,034**	(264)	(64)	0.3	0.0	0.0	0.0	(328)
2016	2,529	2,220	2,337	2,529	2,528	2,529	2,529	**2,029**	(309)	(192)	0.4	(0.2)	0.0	0.0	(500)
2017	2,485	2,130	2,356	2,486	2,482	2,485	2,485	**1,998**	(355)	(129)	0.6	(3.2)	(0.1)	0.0	(487)
2018	2,463	2,061	2,402	2,464	2,448	2,463	2,463	**1,986**	(403)	(61)	1.3	(15.0)	(0.5)	0.0	(478)
2019	2,418	1,968	2,409	2,420	2,391	2,413	2,418	**1,929**	(450)	(9)	2.2	(27.3)	(5.0)	0.1	(489)
2020	2,561	2,064	2,479	2,563	2,535	2,547	2,561	**1,946**	(496)	(82)	2.4	(26.2)	(13.8)	0.2	(615)
2021	2,609	2,074	2,512	2,612	2,583	2,579	2,609	**1,925**	(535)	(97)	3.3	(25.8)	(29.7)	0.5	(683)
2022	2,707	2,149	2,597	2,712	2,672	2,658	2,708	**1,960**	(558)	(110)	5.0	(34.8)	(49.5)	1.0	(747)
2023	2,556	1,981	2,556	2,566	2,529	2,558	2,558	**1,967**	(575)	0	9.9	(26.9)	1.8	1.5	(589)
2024	2,591	2,000	2,591	2,606	2,562	2,593	2,593	**1,992**	(591)	0	15.6	(28.6)	2.4	2.6	(599)
2025	2,627	2,023	2,627	2,650	2,597	2,630	2,631	**2,023**	(604)	0	23.1	(30.4)	2.8	3.9	(605)
2026	2,651	2,035	2,651	2,684	2,619	2,654	2,656	**2,045**	(616)	0	33.2	(31.8)	3.2	5.4	(606)
2027	2,691	2,065	2,691	2,738	2,658	2,694	2,698	**2,090**	(626)	0	46.8	(33.1)	3.5	7.4	(601)
2028	2,724	2,090	2,724	2,788	2,689	2,727	2,733	**2,133**	(634)	0	64.8	(34.7)	3.7	9.7	(590)
2029	2,755	2,114	2,755	2,844	2,718	2,759	2,767	**2,183**	(641)	0	89.2	(36.3)	3.9	12.2	(572)
2030	2,784	2,137	2,784	2,905	2,746	2,788	2,799	**2,239**	(647)	0	121.1	(37.7)	4.1	15.0	(544)
2031	2,812	2,160	2,812	2,973	2,773	2,816	2,830	**2,305**	(652)	0	161.5	(38.9)	4.2	18.2	(507)
2032	2,840	2,184	2,840	3,048	2,800	2,844	2,862	**2,378**	(656)	0	208.3	(39.9)	4.3	22.1	(461)
2033	2,868	2,208	2,868	3,128	2,827	2,872	2,895	**2,458**	(660)	0	259.6	(41.1)	4.4	26.7	(410)
2034	2,895	2,232	2,895	3,210	2,853	2,899	2,927	**2,541**	(663)	0	314.8	(42.2)	4.4	32.0	(354)
2035	2,910	2,245	2,910	3,284	2,867	2,915	2,948	**2,617**	(666)	0	373.2	(43.4)	4.5	37.9	(294)
2036	2,942	2,274	2,942	3,375	2,897	2,946	2,986	**2,711**	(668)	0	433.1	(44.7)	4.5	44.0	(231)
2037	2,950	2,280	2,950	3,442	2,904	2,955	3,001	**2,780**	(671)	0	491.6	(46.0)	4.6	50.4	(170)
2038	2,983	2,310	2,983	3,531	2,935	2,987	3,040	**2,872**	(673)	0	548.5	(47.4)	4.6	56.8	(111)
2039	3,008	2,333	3,008	3,615	2,959	3,013	3,071	**2,958**	(676)	0	606.8	(48.8)	4.6	63.0	(50)
2040	3,040	2,361	3,040	3,709	2,990	3,044	3,108	**3,055**	(678)	0	669.7	(49.8)	4.6	68.9	15
2041	3,069	2,389	3,069	3,778	3,019	3,074	3,144	**3,126**	(681)	0	709.0	(50.6)	4.6	74.5	57
2042	3,086	2,403	3,086	3,830	3,035	3,090	3,165	**3,180**	(683)	0	744.3	(51.2)	4.7	79.5	94
2043	3,101	2,416	3,101	3,877	3,050	3,106	3,185	**3,229**	(686)	0	775.8	(51.9)	4.7	84.0	127
2044	3,130	2,442	3,130	3,934	3,078	3,135	3,218	**3,286**	(688)	0	803.7	(52.5)	4.7	87.8	156
2045	3,153	2,463	3,153	3,981	3,100	3,158	3,244	**3,333**	(690)	0	827.9	(53.2)	4.7	91.0	180
2046	3,191	2,498	3,191	4,040	3,137	3,196	3,285	**3,391**	(693)	0	848.8	(54.0)	4.7	93.6	200
2047	3,216	2,521	3,216	4,083	3,161	3,221	3,312	**3,433**	(695)	0	866.6	(54.7)	4.7	95.6	217
2048	3,219	2,521	3,219	4,101	3,163	3,224	3,316	**3,449**	(698)	0	881.7	(55.5)	4.7	97.0	230
2049	3,262	2,562	3,262	4,156	3,206	3,267	3,360	**3,502**	(700)	0	894.5	(56.3)	4.7	97.9	240
2050	3,293	2,590	3,293	4,198	3,236	3,297	3,391	**3,541**	(703)	0	905.3	(57.1)	4.7	98.4	248

	Reconstituted (before DER)	w/ EE only	w/ PV only	w/ EV only	w/ DR only	w/ ES only	w/ EH only	Final Forecast (after all DER)
Avg. last 15 yrs	1.5%	0.1%	1.2%	1.5%	1.4%	1.4%	1.5%	-0.5%
Avg. last 10 yrs	1.9%	0.3%	1.5%	1.9%	1.8%	1.7%	1.9%	-0.6%
Avg. last 5 yrs	1.7%	0.2%	2.0%	1.8%	1.5%	1.4%	1.7%	-0.4%
BASE 2022								
Avg. next 5 yrs	-0.1%	-0.8%	0.7%	0.2%	-0.1%	0.3%	-0.1%	1.3%
Avg. next 10 yrs	0.5%	0.2%	0.9%	1.2%	0.5%	0.7%	0.6%	2.0%
Avg. next 15 yrs	0.6%	0.4%	0.9%	1.6%	0.6%	0.7%	0.7%	2.4%
Avg. next 20 yrs	0.7%	0.6%	0.9%	1.7%	0.6%	0.8%	0.8%	2.4%
Avg. next 25 yrs	0.7%	0.6%	0.9%	1.6%	0.7%	0.8%	0.8%	2.3%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating Pump Cooling (reduces load)

WCMA
WINTER Peaks

after DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 10-90 (MW)	Extreme 10-90 (% Grwth)	Extreme 05-95 (MW)	Extreme 05-95 (% Grwth)	HDD_wtd ACTUAL
2006	1,764		1,756		1,804		1,818		51.9
2007	1,778	0.8%	1,748	-0.4%	1,796	-0.4%	1,810	-0.4%	51.3
2008	1,717	-3.4%	1,746	-0.1%	1,797	0.0%	1,811	0.1%	44.7
2009	1,701	-0.9%	1,741	-0.3%	1,793	-0.2%	1,808	-0.2%	42.5
2010	1,740	2.3%	1,676	-3.7%	1,731	-3.5%	1,746	-3.4%	59.2
2011	1,637	-5.9%	1,671	-0.3%	1,726	-0.3%	1,741	-0.3%	45.9
2012	1,719	5.0%	1,692	1.2%	1,743	1.0%	1,758	1.0%	54.1
2013	1,776	3.3%	1,780	5.2%	1,834	5.2%	1,850	5.2%	49.8
2014	1,677	-5.6%	1,669	-6.2%	1,722	-6.1%	1,737	-6.1%	54.3
2015	1,589	-5.2%	1,627	-2.6%	1,678	-2.6%	1,692	-2.6%	46.2
2016	1,595	0.3%	1,596	-1.9%	1,655	-1.3%	1,672	-1.2%	52.8
2017	1,673	4.9%	1,594	-0.1%	1,665	0.6%	1,685	0.8%	59.0
2018	1,691	1.1%	1,633	2.5%	1,695	1.8%	1,712	1.6%	57.3
2019	1,515	-10.4%	1,545	-5.4%	1,604	-5.4%	1,621	-5.3%	46.6
2020	1,501	-1.0%	1,584	2.6%	1,648	2.7%	1,666	2.8%	43.9
2021	1,621	8.0%	1,604	1.2%	1,665	1.0%	1,682	1.0%	49.5
2022	-	-	1,604	0.0%	1,671	0.4%	1,690	0.5%	-
2023		-	1,572	-2.0%	1,639	-1.9%	1,658	-1.9%	
2024		-	1,589	1.1%	1,658	1.1%	1,677	1.1%	
2025	-	-	1,606	1.1%	1,676	1.1%	1,695	1.1%	-
2026	-	-	1,648	2.6%	1,715	2.4%	1,734	2.3%	-
2027	-	-	1,692	2.7%	1,760	2.6%	1,779	2.6%	-
2028	-	-	1,754	3.7%	1,823	3.6%	1,842	3.6%	-
2029	-	-	1,817	3.6%	1,887	3.5%	1,906	3.5%	-
2030	-	-	1,899	4.5%	1,970	4.4%	1,990	4.4%	-
2031	-	-	2,001	5.4%	2,073	5.2%	2,093	5.2%	-
2032	-	-	2,121	6.0%	2,193	5.8%	2,214	5.8%	-
2033	-	-	2,259	6.5%	2,332	6.3%	2,353	6.3%	-
2034	-	-	2,411	6.7%	2,485	6.6%	2,506	6.5%	-
2035	-	-	2,579	6.9%	2,654	6.8%	2,675	6.7%	-
2036	-	-	2,754	6.8%	2,830	6.6%	2,851	6.6%	-
2037	-		2,939	6.7%	3,016	6.6%	3,038	6.5%	-
2038	-		3,105	5.7%	3,183	5.5%	3,205	5.5%	-
2039	-		3,279	5.6%	3,358	5.5%	3,380	5.5%	-
2040	-		3,467	5.7%	3,546	5.6%	3,569	5.6%	-
2041	-		3,614	4.2%	3,694	4.2%	3,717	4.2%	-
2042	-		3,759	4.0%	3,840	4.0%	3,863	3.9%	-
2043	-		3,892	3.5%	3,974	3.5%	3,998	3.5%	-
2044	-		4,021	3.3%	4,105	3.3%	4,129	3.3%	-
2045	-		4,130	2.7%	4,216	2.7%	4,240	2.7%	-
2046	-		4,227	2.3%	4,313	2.3%	4,337	2.3%	-
2047	-		4,319	2.2%	4,406	2.1%	4,430	2.1%	-
2048	-		4,406	2.0%	4,494	2.0%	4,519	2.0%	-
2049	-		4,451	1.0%	4,540	1.0%	4,565	1.0%	-
2050	-		4,477	0.6%	4,567	0.6%	4,592	0.6%	-

	Normal 50-50	Extreme 10-90	Extreme 05-95
Avg. last 15 yrs	-0.6%	-0.5%	-0.5%
Avg. last 10 yrs	-0.4%	-0.4%	-0.3%
Avg. last 5 yrs	0.1%	0.1%	0.1%
BASE 2020			
Avg. next 5 yrs	0.5%	0.6%	0.6%
Avg. next 10 yrs	2.2%	2.2%	2.2%
Avg. next 15 yrs	3.7%	3.6%	3.6%
Avg. next 20 yrs	4.1%	4.1%	4.0%
Avg. next 25 yrs	4.0%	3.9%	3.9%

HDD_wtd

NORMAL	50.4
EXTREME 90/10	58.2
EXTREME 95/5	60.4

** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response*

WCMA	WINTER 50/50 Peaks (MW) (before & after DERs)														
	SYSTEM PEAK								DER IMPACTS						
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2006	1,838	1,756	1,838	1,838	1,838	1,838	1,838	**1,756**	(82)	0	0.0	0.0	0.0	0.0	(82)
2007	1,856	1,748	1,856	1,856	1,856	1,856	1,856	**1,748**	(108)	0	0.0	0.0	0.0	0.0	(108)
2008	1,870	1,746	1,870	1,870	1,870	1,870	1,870	**1,746**	(124)	0	0.0	0.0	0.0	0.0	(124)
2009	1,894	1,741	1,894	1,894	1,894	1,894	1,894	**1,741**	(152)	0	0.0	0.0	0.0	0.0	(152)
2010	1,854	1,676	1,854	1,854	1,854	1,854	1,854	**1,676**	(178)	0	0.0	0.0	0.0	0.0	(178)
2011	1,877	1,671	1,877	1,877	1,877	1,877	1,877	**1,671**	(206)	0	0.0	0.0	0.0	0.0	(206)
2012	1,928	1,692	1,928	1,928	1,928	1,928	1,928	**1,692**	(236)	0	0.1	0.0	0.0	0.0	(236)
2013	2,057	1,780	2,057	2,057	2,057	2,057	2,057	**1,780**	(277)	0	0.2	0.0	0.0	0.0	(277)
2014	1,991	1,669	1,991	1,991	1,991	1,991	1,991	**1,669**	(322)	0	0.4	0.0	0.0	0.0	(322)
2015	1,998	1,626	1,998	1,999	1,998	1,998	1,998	**1,627**	(372)	0	0.6	0.0	0.0	0.0	(371)
2016	2,018	1,595	2,018	2,019	2,018	2,018	2,018	**1,596**	(423)	0	0.8	0.0	0.0	0.0	(422)
2017	2,067	1,592	2,067	2,069	2,067	2,067	2,067	**1,594**	(475)	0	1.2	0.0	(0.2)	0.0	(474)
2018	2,164	1,632	2,164	2,166	2,164	2,163	2,164	**1,633**	(532)	0	2.0	0.0	(0.8)	0.0	(531)
2019	2,139	1,550	2,139	2,142	2,139	2,131	2,139	**1,545**	(589)	0	2.6	0.0	(7.9)	0.3	(594)
2020	2,243	1,598	2,243	2,246	2,243	2,224	2,244	**1,584**	(645)	0	3.4	0.0	(18.3)	1.0	(658)
2021	2,317	1,635	2,317	2,321	2,317	2,278	2,318	**1,604**	(681)	0	4.7	0.0	(38.2)	1.8	(713)
2022	2,351	1,650	2,351	2,358	2,351	2,293	2,355	**1,604**	(700)	0	7.4	0.0	(58.2)	4.2	(747)
2023	2,346	1,629	2,346	2,359	2,346	2,268	2,355	**1,572**	(717)	0	12.4	0.0	(78.2)	9.0	(774)
2024	2,386	1,653	2,386	2,405	2,386	2,288	2,401	**1,589**	(733)	0	19.2	0.0	(98.1)	15.3	(797)
2025	2,417	1,670	2,417	2,445	2,417	2,303	2,439	**1,606**	(747)	0	28.1	0.0	(114.0)	21.7	(811)
2026	2,324	1,566	2,324	2,377	2,324	2,327	2,350	**1,648**	(758)	0	53.4	0.0	3.5	25.9	(676)
2027	2,348	1,580	2,348	2,423	2,348	2,352	2,382	**1,692**	(768)	0	74.8	0.0	3.8	33.8	(656)
2028	2,381	1,605	2,381	2,484	2,381	2,385	2,424	**1,754**	(776)	0	102.9	0.0	4.0	42.7	(627)
2029	2,402	1,619	2,402	2,544	2,402	2,406	2,454	**1,817**	(784)	0	142.0	0.0	4.2	52.3	(585)
2030	2,431	1,641	2,431	2,622	2,431	2,435	2,493	**1,899**	(790)	0	190.9	0.0	4.4	62.5	(532)
2031	2,459	1,664	2,459	2,713	2,459	2,463	2,538	**2,001**	(795)	0	253.6	0.0	4.5	78.8	(458)
2032	2,487	1,688	2,487	2,809	2,487	2,491	2,594	**2,121**	(799)	0	322.1	0.0	4.6	106.7	(366)
2033	2,515	1,712	2,515	2,912	2,515	2,519	2,660	**2,259**	(803)	0	396.9	0.0	4.6	145.5	(256)
2034	2,542	1,736	2,542	3,018	2,542	2,546	2,736	**2,411**	(806)	0	476.7	0.0	4.7	194.2	(130)
2035	2,571	1,763	2,571	3,131	2,571	2,576	2,823	**2,579**	(808)	0	559.8	0.0	4.7	251.5	8
2036	2,601	1,789	2,601	3,244	2,601	2,605	2,917	**2,754**	(811)	0	643.4	0.0	4.8	316.1	153
2037	2,637	1,823	2,637	3,362	2,637	2,641	3,023	**2,939**	(814)	0	725.0	0.0	4.8	386.4	302
2038	2,653	1,836	2,653	3,456	2,653	2,657	3,113	**3,105**	(816)	0	803.8	0.0	4.8	460.5	453
2039	2,672	1,853	2,672	3,557	2,672	2,677	3,209	**3,279**	(819)	0	884.8	0.0	4.9	536.7	607
2040	2,698	1,876	2,698	3,671	2,698	2,703	3,311	**3,467**	(822)	0	973.1	0.0	4.9	613.2	769
2041	2,720	1,895	2,720	3,746	2,720	2,724	3,408	**3,614**	(824)	0	1,026.2	0.0	4.9	688.2	895
2042	2,747	1,920	2,747	3,821	2,747	2,752	3,507	**3,759**	(827)	0	1,074.2	0.0	4.9	760.1	1,012
2043	2,773	1,943	2,773	3,890	2,773	2,778	3,600	**3,892**	(830)	0	1,117.0	0.0	4.9	827.2	1,119
2044	2,887	2,054	2,887	4,015	2,887	2,709	3,902	**4,021**	(832)	0	1,128.6	0.0	(177.3)	1,015.2	1,134
2045	2,906	2,071	2,906	4,067	2,906	2,728	3,982	**4,130**	(835)	0	1,160.7	0.0	(177.7)	1,076.5	1,224
2046	2,926	2,088	2,926	4,114	2,926	2,748	4,054	**4,227**	(838)	0	1,188.3	0.0	(177.7)	1,128.2	1,301
2047	2,955	2,115	2,955	4,167	2,955	2,778	4,125	**4,319**	(840)	0	1,211.8	0.0	(177.7)	1,169.4	1,363
2048	2,995	2,152	2,995	4,227	2,995	2,818	4,195	**4,406**	(843)	0	1,231.9	0.0	(177.7)	1,199.3	1,410
2049	3,008	2,163	3,008	4,257	3,008	2,831	4,226	**4,451**	(846)	0	1,249.0	0.0	(177.7)	1,217.4	1,443
2050	3,016	2,168	3,016	4,280	3,016	2,839	4,240	**4,477**	(848)	0	1,263.6	0.0	(177.7)	1,223.5	1,461

Avg. last 15 yrs	1.6%	-0.5%	1.6%	1.6%	1.6%	1.4%	1.6%	-0.6%
Avg. last 10 yrs	2.1%	-0.2%	2.1%	2.1%	2.1%	2.0%	2.1%	-0.4%
Avg. last 5 yrs	2.8%	0.5%	2.8%	2.8%	2.8%	2.5%	2.8%	0.1%
BASE 2020								
Avg. next 5 yrs	0.1%	-0.9%	0.1%	0.5%	0.1%	0.4%	0.3%	0.5%
Avg. next 10 yrs	0.6%	0.2%	0.6%	1.6%	0.6%	0.8%	0.9%	2.2%
Avg. next 15 yrs	0.8%	0.6%	0.8%	2.3%	0.8%	0.9%	1.5%	3.7%
Avg. next 20 yrs	0.8%	0.7%	0.8%	2.4%	0.8%	0.9%	1.9%	4.1%
Avg. next 25 yrs	0.9%	1.0%	0.9%	2.3%	0.9%	0.8%	2.3%	4.0%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating/Cooling (ADDs to load)

Nantucket (COMPANY)

NANT
Annual Peaks

AFTER DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	Peak Season (50-50)
2006	39		37		39		39		S
2007	39	-1.2%	41	10.5%	43	11.9%	44	12.2%	S
2008	39	-0.5%	40	-1.5%	42	-2.2%	43	-2.4%	S
2009	39	1.3%	40	1.2%	43	1.5%	44	1.6%	S
2010	40	2.7%	39	-3.2%	42	-1.9%	43	-1.6%	S
2011	41	0.8%	41	5.4%	44	5.1%	45	5.0%	S
2012	44	8.2%	45	8.2%	47	6.5%	48	6.1%	S
2013	45	3.7%	45	0.2%	47	0.7%	48	0.8%	S
2014	41	-10.9%	45	0.1%	48	1.0%	49	1.3%	S
2015	46	12.5%	44	-2.5%	47	-1.3%	48	-1.0%	S
2016	50	10.3%	49	12.1%	53	11.8%	54	11.7%	S
2017	46	-8.7%	46	-6.9%	49	-7.9%	50	-8.2%	S
2018	50	8.9%	49	7.2%	53	9.1%	54	9.6%	S
2019	51	1.2%	47	-3.5%	51	-4.6%	52	-4.8%	S
2020	52	2.5%	48	2.4%	54	7.3%	56	8.5%	S
2021	53	2.4%	51	6.3%	56	2.0%	57	1.0%	S
2022	58	9.4%	52	1.0%	58	3.9%	59	4.7%	S
2023	-	-	53	2.1%	59	2.2%	61	2.2%	S
2024	-	-	54	1.7%	60	1.8%	62	1.9%	S
2025	-	-	55	1.7%	61	1.7%	63	1.8%	S
2026	-	-	56	1.9%	62	2.0%	64	2.0%	S
2027	-	-	57	2.2%	64	2.3%	66	2.3%	S
2028	-	-	58	2.3%	65	2.3%	67	2.3%	S
2029	-	-	60	2.4%	67	2.2%	69	2.2%	S
2030	-	-	61	2.3%	68	2.2%	70	2.2%	S
2031	-	-	63	2.5%	70	2.4%	72	2.4%	S
2032	-	-	64	2.5%	72	2.4%	74	2.4%	S
2033	-	-	66	2.5%	73	2.4%	75	2.4%	S
2034	-	-	67	2.6%	75	2.5%	77	2.5%	S
2035	-	-	69	2.5%	77	2.4%	79	2.4%	S
2036	-	-	71	2.4%	79	2.4%	81	2.4%	S
2037	-	-	72	2.3%	81	2.3%	83	2.3%	S
2038	-		74	2.2%	82	2.2%	85	2.1%	S
2039	-		76	2.2%	84	2.1%	86	2.1%	S
2040	-		77	2.1%	86	2.1%	88	2.1%	S
2041	-		79	1.7%	87	1.7%	90	1.6%	S
2042	-		80	1.5%	88	1.5%	91	1.5%	S
2043	-		81	1.4%	90	1.4%	92	1.4%	S
2044	-		82	1.2%	91	1.2%	93	1.2%	S
2045	-		83	1.1%	92	1.1%	94	1.1%	S
2046	-		84	1.0%	93	1.0%	95	1.0%	S
2047	-		84	0.9%	94	0.9%	96	0.9%	S
2048	-		85	0.8%	94	0.8%	97	0.8%	S
2049	-		86	0.7%	95	0.7%	98	0.7%	S
2050	-		86	0.6%	96	0.6%	98	0.6%	S

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	1.7%	1.9%	2.0%
Avg. last 10 yrs	1.5%	2.0%	2.2%
Avg. last 5 yrs	2.6%	3.4%	3.7%
Base 2022			
Avg. next 5 yrs	1.9%	2.0%	2.0%
Avg. next 10 yrs	2.1%	2.2%	2.2%
Avg. next 15 yrs	2.3%	2.2%	2.2%
Avg. next 20 yrs	2.2%	2.2%	2.2%
Avg. next 25 yrs	2.0%	2.0%	1.9%

***** *impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heat pumps, and company demand response***

NANT — Annual 50/50 Peaks (MW) (before & after DERs)

Calendar Year	SYSTEM PEAK: Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	DER IMPACTS: EE	PV	EV	DR	ES	EH	DER
2006	37	37	37	37	37	37	37	**37**	(1)	(0)	0.0	0.0	0.0	0.0	(1)
2007	41	41	41	41	41	41	41	**41**	(1)	(0)	0.0	0.0	0.0	0.0	(1)
2008	41	40	41	41	41	41	41	**40**	(1)	(0)	0.0	0.0	0.0	0.0	(1)
2009	41	40	41	41	41	41	41	**40**	(1)	(0)	0.0	0.0	0.0	0.0	(1)
2010	40	39	40	40	40	40	40	**39**	(1)	(0)	0.0	0.0	0.0	0.0	(1)
2011	43	41	43	43	43	43	43	**41**	(2)	(0)	0.0	0.0	0.0	0.0	(2)
2012	46	45	46	46	46	46	46	**45**	(2)	(0)	0.0	0.0	0.0	0.0	(2)
2013	47	45	47	47	47	47	47	**45**	(2)	(0)	0.0	0.0	0.0	0.0	(2)
2014	47	45	47	47	47	47	47	**45**	(3)	(0)	0.0	0.0	0.0	0.0	(3)
2015	47	44	47	47	47	47	47	**44**	(3)	(0)	0.0	0.0	0.0	0.0	(3)
2016	53	49	52	53	53	53	53	**49**	(4)	(0)	0.0	(0.0)	0.0	0.0	(4)
2017	50	46	50	50	50	50	50	**46**	(4)	(0)	0.0	(0.0)	0.0	0.0	(4)
2018	54	49	53	54	54	54	54	**49**	(5)	(1)	0	(0)	0	0	(5)
2019	53	48	52	53	53	53	53	**47**	(5)	(1)	0	(0)	0	0	(6)
2020	54	48	54	54	54	54	54	**48**	(6)	(0)	0	(0)	0	0	(6)
2021	58	52	57	58	58	58	58	**51**	(6)	(1)	0	(0)	0	0	(7)
2022	64	58	58	64	64	64	64	**52**	(6)	(6)	0	0	0	0	(12)
2023	61	54	60	61	60	61	61	**53**	(7)	(1)	0	(0)	0	0	(8)
2024	62	55	61	62	62	62	62	**54**	(7)	(1)	0	(0)	0	0	(8)
2025	63	56	62	63	63	63	63	**55**	(7)	(1)	0	(0)	0	0	(8)
2026	64	57	63	64	64	64	64	**56**	(7)	(1)	0	(0)	0	0	(8)
2027	65	58	64	66	65	65	65	**57**	(7)	(1)	0	(0)	0	0	(8)
2028	65	58	65	66	65	65	65	**58**	(7)	(0)	1	(0)	0	0	(7)
2029	66	59	66	67	66	66	66	**60**	(7)	(0)	1	(0)	0	0	(7)
2030	67	60	67	69	67	67	68	**61**	(8)	(0)	1	(0)	0	0	(6)
2031	68	61	68	70	68	68	69	**63**	(8)	(0)	2	(0)	0	0	(6)
2032	69	62	69	72	69	69	70	**64**	(8)	(0)	2	(0)	0	0	(5)
2033	70	63	70	74	70	70	71	**66**	(8)	(0)	3	(0)	0	0	(5)
2034	71	64	71	75	71	71	72	**67**	(8)	(0)	4	(0)	0	0	(4)
2035	72	65	72	77	72	72	73	**69**	(8)	(0)	4	(0)	0	0	(3)
2036	73	66	73	79	73	73	74	**71**	(8)	(0)	5	(0)	0	1	(3)
2037	74	66	74	80	74	74	75	**72**	(8)	(0)	6	(0)	0	1	(2)
2038	75	67	75	82	75	75	76	**74**	(8)	(0)	7	(0)	0	1	(1)
2039	76	68	76	83	76	76	77	**76**	(8)	(0)	7	(0)	0	1	(1)
2040	77	69	77	85	77	77	78	**77**	(8)	(0)	8	(0)	0	1	0
2041	78	70	77	86	77	78	79	**79**	(8)	(0)	8	(0)	0	1	1
2042	79	71	78	87	78	79	80	**80**	(8)	(0)	9	(0)	0	1	1
2043	79	71	79	89	79	79	80	**81**	(8)	(0)	9	(0)	0	1	2
2044	80	72	79	90	80	80	81	**82**	(8)	(0)	10	(0)	0	1	2
2045	81	72	80	90	80	81	82	**83**	(8)	(0)	10	(0)	0	1	2
2046	81	73	81	91	81	81	82	**84**	(8)	(0)	10	(0)	0	1	2
2047	82	74	81	92	81	82	83	**84**	(8)	(0)	10	(0)	0	1	3
2048	82	74	82	93	82	82	83	**85**	(8)	(0)	11	(0)	0	1	3
2049	83	74	82	93	82	83	84	**86**	(8)	(0)	11	(0)	0	1	3
2050	83	75	83	94	83	83	84	**86**	(8)	(0)	11	(0)	0	1	3

	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)
Avg. last 15 yrs	3.0%	2.4%	2.3%	3.0%	3.0%	3.0%	3.0%	1.7%
Avg. last 10 yrs	3.3%	2.6%	2.3%	3.3%	3.3%	3.3%	3.3%	1.5%
Avg. last 5 yrs	5.3%	4.8%	3.2%	5.3%	5.3%	5.3%	5.3%	2.6%
Base 2022								
Avg. next 5 yrs	0.3%	0.1%	1.9%	0.5%	0.3%	0.3%	0.4%	1.9%
Avg. next 10 yrs	0.8%	0.7%	1.7%	1.1%	0.8%	0.8%	0.8%	2.1%
Avg. next 15 yrs	1.0%	0.9%	1.6%	1.5%	1.0%	1.0%	1.0%	2.3%
Avg. next 20 yrs	1.0%	1.0%	1.5%	1.6%	1.0%	1.0%	1.1%	2.2%
Avg. next 25 yrs	1.0%	1.0%	1.3%	1.4%	0.9%	1.0%	1.0%	2.0%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating Pump Cooling (Adds load)

NANT
WINTER Peaks

after DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 10-90 (MW)	Extreme 10-90 (% Grwth)	Extreme 05-95 (MW)	Extreme 05-95 (% Grwth)	HDD_wtd ACTUAL
2006	28		30		32		33		41.0
2007	28	0.9%	33	9.8%	35	7.6%	35	7.1%	27.3
2008	25	-9.4%	25	-23.2%	27	-22.3%	27	-22.1%	43.9
2009	26	1.4%	27	8.4%	29	8.0%	29	7.9%	35.0
2010	25	-3.2%	26	-4.9%	28	-5.0%	28	-5.1%	37.4
2011	24	-4.6%	25	-3.8%	27	-3.6%	27	-3.6%	39.1
2012	27	14.5%	26	6.0%	28	7.3%	29	7.6%	50.0
2013	29	7.9%	30	13.1%	32	12.2%	33	12.0%	36.2
2014	30	1.1%	28	-4.6%	30	-4.6%	31	-4.6%	48.8
2015	30	1.6%	28	-1.2%	30	0.1%	31	0.5%	52.9
2016	29	-4.4%	29	3.2%	32	3.8%	32	4.0%	42.1
2017	32	12.0%	31	7.0%	34	8.2%	35	8.6%	47.9
2018	33	3.6%	33	5.6%	36	3.9%	36	3.5%	44.0
2019	29	-12.6%	31	-4.7%	34	-4.0%	35	-3.8%	36.7
2020	33	11.6%	33	5.9%	36	4.1%	36	3.7%	41.2
2021	32	-2.1%	33	0.9%	36	2.3%	37	2.7%	38.6
2022	-	-	34	1.8%	37	1.9%	38	1.9%	-
2023		-	35	2.4%	38	2.4%	39	2.4%	
2024		-	35	2.2%	39	2.2%	40	2.1%	
2025	-	-	36	2.1%	40	2.1%	41	2.1%	-
2026	-	-	37	2.5%	41	2.5%	42	2.5%	-
2027	-	-	38	2.9%	42	2.8%	43	2.8%	-
2028	-	-	39	3.1%	43	3.0%	44	3.0%	-
2029	-	-	41	3.2%	44	3.1%	45	3.1%	-
2030	-	-	42	3.2%	46	3.1%	47	3.1%	-
2031	-	-	44	3.7%	47	3.6%	48	3.5%	-
2032	-	-	45	4.0%	49	3.9%	50	3.8%	-
2033	-	-	47	4.3%	51	4.1%	52	4.1%	-
2034	-	-	49	4.6%	53	4.4%	55	4.3%	-
2035	-	-	52	4.6%	56	4.4%	57	4.3%	-
2036	-	-	54	4.6%	58	4.4%	59	4.3%	-
2037	-		57	4.5%	61	4.3%	62	4.2%	-
2038	-		59	4.4%	63	4.2%	64	4.1%	-
2039	-		62	4.3%	66	4.1%	67	4.0%	-
2040	-		64	4.2%	69	4.0%	70	4.0%	-
2041	-		66	3.3%	71	3.2%	72	3.2%	-
2042	-		68	3.0%	73	2.9%	74	2.9%	-
2043	-		70	2.7%	75	2.6%	76	2.6%	-
2044	-		72	2.4%	76	2.3%	78	2.3%	-
2045	-		73	2.1%	78	2.0%	79	2.0%	-
2046	-		75	1.8%	79	1.7%	80	1.7%	-
2047	-		76	1.5%	80	1.4%	82	1.4%	-
2048	-		77	1.2%	81	1.2%	83	1.2%	-
2049	-		77	0.9%	82	0.9%	83	0.9%	-
2050	-		78	0.7%	83	0.7%	84	0.7%	-

	Normal 50-50	Extreme 10-90	Extreme 05-95
Avg. last 15 yrs	0.8%	0.8%	0.9%
Avg. last 10 yrs	3.0%	3.2%	3.3%
Avg. last 5 yrs	2.8%	2.8%	2.8%
Base 2021			
Avg. next 5 yrs	2.2%	2.2%	2.2%
Avg. next 10 yrs	2.7%	2.7%	2.6%
Avg. next 14 yrs	3.5%	3.4%	3.4%

HDD_wtd

NORMAL	42.6
EXTREME 90/10	51.5
EXTREME 95/5	54.1

***** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response (solar and demand response are zero at times of winter peak)***

NANT	WINTER 50/50 Peaks (MW) (before & after DERs)															
	SYSTEM PEAK								DER IMPACTS							
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2006	31	30	31	31	31	31	31	**30**	(1)	0	0.0	0.0	0.0	0.0	(1)
2007	34	33	34	34	34	34	34	**33**	(1)	0	0.0	0.0	0.0	0.0	(1)
2008	26	25	26	26	26	26	26	**25**	(1)	0	0.0	0.0	0.0	0.0	(1)
2009	29	27	29	29	29	29	29	**27**	(2)	0	0.0	0.0	0.0	0.0	(2)
2010	28	26	28	28	28	28	28	**26**	(2)	0	0.0	0.0	0.0	0.0	(2)
2011	27	25	27	27	27	27	27	**25**	(2)	0	0.0	0.0	0.0	0.0	(2)
2012	29	26	29	29	29	29	29	**26**	(3)	0	0.0	0.0	0.0	0.0	(3)
2013	33	30	33	33	33	33	33	**30**	(3)	0	0.0	0.0	0.0	0.0	(3)
2014	32	28	32	32	32	32	32	**28**	(4)	0	0.0	0.0	0.0	0.0	(4)
2015	32	29	31	32	32	32	32	**28**	(3)	(1)	0.0	0.0	0.0	0.0	(4)
2016	32	29	32	32	32	32	32	**29**	(3)	(0)	0.0	0.0	0.0	0.0	(3)
2017	36	31	36	36	36	36	36	**31**	(5)	0	0.0	0.0	0.0	0.0	(5)
2018	39	33	39	39	39	39	39	**33**	(6)	0	0.0	0.0	0.0	0.0	(6)
2019	38	31	38	38	38	38	38	**31**	(6)	0	0.0	0.0	0.0	0.0	(6)
2020	40	33	40	40	40	40	40	**33**	(7)	0	0.0	0.0	0.0	0.0	(7)
2021	45	37	41	45	45	45	45	**33**	(8)	(4)	0.0	0.0	0.0	0.0	(12)
2022	41	34	41	42	41	41	42	**34**	(8)	0	0.1	0.0	0.0	0.0	(8)
2023	42	34	42	43	42	42	42	**35**	(8)	0	0.2	0.0	0.0	0.1	(8)
2024	43	35	43	43	43	43	43	**35**	(8)	0	0.3	0.0	0.0	0.2	(8)
2025	44	36	44	44	44	44	44	**36**	(8)	0	0.4	0.0	0.0	0.3	(8)
2026	45	36	45	45	45	45	45	**37**	(8)	0	0.6	0.0	0.0	0.3	(7)
2027	45	37	45	46	45	45	46	**38**	(8)	0	0.8	0.0	0.0	0.4	(7)
2028	46	38	46	47	46	46	47	**39**	(9)	0	1.1	0.0	0.0	0.6	(7)
2029	47	38	47	49	47	47	48	**41**	(9)	0	1.6	0.0	0.0	0.7	(6)
2030	48	39	48	50	48	48	49	**42**	(9)	0	2.1	0.0	0.0	0.8	(6)
2031	48	40	48	51	48	48	50	**44**	(9)	0	2.8	0.0	0.0	1.0	(5)
2032	49	40	49	53	49	49	51	**45**	(9)	0	3.6	0.0	0.0	1.4	(4)
2033	50	41	50	54	50	50	52	**47**	(9)	0	4.4	0.0	0.0	1.9	(3)
2034	50	42	50	56	50	50	53	**49**	(9)	0	5.3	0.0	0.0	2.6	(1)
2035	51	42	51	57	51	51	54	**52**	(9)	0	6.2	0.0	0.0	3.3	1
2036	52	43	52	59	52	52	56	**54**	(9)	0	7.2	0.0	0.0	4.2	2
2037	52	43	52	60	52	52	57	**57**	(9)	0	8.7	0.0	0.0	5.1	5
2038	52	43	52	62	52	52	58	**59**	(9)	0	9.7	0.0	0.0	6.1	7
2039	53	44	53	64	53	53	60	**62**	(9)	0	10.7	0.0	0.0	7.1	9
2040	53	44	53	65	53	53	62	**64**	(9)	0	11.7	0.0	0.0	8.1	11
2041	54	45	54	66	54	54	63	**66**	(9)	0	12.4	0.0	0.0	9.1	12
2042	55	45	55	67	55	55	65	**68**	(9)	0	12.9	0.0	0.0	10.1	14
2043	55	46	55	68	55	55	66	**70**	(9)	0	13.5	0.0	0.0	11.0	15
2044	55	46	55	69	55	55	67	**72**	(9)	0	13.9	0.0	0.0	11.8	17
2045	56	47	56	70	56	56	68	**73**	(9)	0	14.3	0.0	0.0	12.5	18
2046	56	47	56	71	56	56	69	**75**	(9)	0	14.6	0.0	0.0	13.1	18
2047	57	47	57	72	57	57	70	**76**	(9)	0	14.9	0.0	0.0	13.6	19
2048	57	48	57	72	57	57	71	**77**	(9)	0	15.2	0.0	0.0	13.9	20
2049	57	48	57	73	57	57	71	**77**	(9)	0	15.4	0.0	0.0	14.1	20
2050	58	48	58	73	58	58	72	**78**	(9)	0	15.6	0.0	0.0	14.2	20

	-							
Avg. last 15 yrs	2.6%	1.5%	1.9%	2.6%	2.6%	2.6%	2.6%	0.8%
Avg. last 10 yrs	5.2%	4.2%	4.2%	5.2%	5.2%	5.2%	5.2%	3.0%
Avg. last 5 yrs	6.8%	5.1%	4.8%	6.8%	6.8%	6.8%	6.8%	2.8%
Base 2021								
Avg. next 5 yrs	-0.1%	-0.6%	1.8%	0.1%	-0.1%	-0.1%	0.0%	2.2%
Avg. next 10 yrs	0.8%	0.6%	1.7%	1.3%	0.8%	0.8%	1.0%	2.7%
Avg. next 15 yrs	1.0%	0.9%	1.6%	1.8%	1.0%	1.0%	1.5%	3.3%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating/Cooling (ADDs to load)

Appendix B: Power Supply Areas

The Company provides peak load growth forecast for the 18 power supply areas in its Massachusetts service territory. The forecasting process leverages regional information to allocates the system-level load growth projection and outlook on distributed energy resources (DER) to the feeder level. The allocations of load growth, energy efficiency, and medium- and heavy-duty electric vehicle growth use regional energy growth information. The allocations on solar PV, light-duty electric vehicles, and electric heat pumps use demographic information, heating fuel type information, and land availability. The feeder level forecasts are then aggregated to the power supply area level, and a year-over-year peak load growth rate is generated and presented in the tables below.

Year One Weather-Adjustment and Multi-Year Annual Growth Percentages (Summer) — **after EE, PV, EV, and EH impacts**

			2022 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg	5-yr avg	5-yr avg
State	PSA	Zone (1)	for 50/50	for 90/10	for 95/5	_2023	_2024	_2025	_2026	_2027	'23 to '27	'28 to '32	'33 to '37	'38 to '42	'43 to '47
MA	Adams	WCMA	97.7%	103.2%	104.8%	2.0	1.8	2.0	1.4	2.4	1.9	3.6	3.9	3.6	2.1
MA	Athol	WCMA	97.7%	103.2%	104.8%	1.7	3.3	0.8	3.2	4.0	2.6	3.9	4.3	2.5	1.1
MA	Attleboro	SEMA	93.6%	102.3%	104.7%	0.1	0.2	0.8	0.3	0.1	0.3	2.5	3.1	2.4	1.1
MA	Brockton	SEMA	93.6%	102.3%	104.7%	0.0	0.3	1.0	0.6	1.5	0.7	2.4	3.5	2.3	1.1
MA	Essex	NEMA	94.7%	102.4%	104.6%	0.6	1.3	1.5	1.2	2.0	1.3	2.6	3.7	2.9	1.3
MA	Fall River	SEMA	93.6%	102.3%	104.7%	0.4	0.5	0.7	0.3	1.5	0.7	2.0	2.9	2.1	1.2
MA	Gardner	WCMA	97.7%	103.2%	104.8%	1.7	2.1	1.8	-0.3	3.0	1.7	2.9	3.5	2.0	0.8
MA	Leominster	WCMA	97.7%	103.2%	104.8%	1.2	1.9	1.8	0.9	1.9	1.5	2.2	2.6	2.8	1.7
MA	Marlboro	WCMA	97.7%	103.2%	104.8%	1.3	1.5	1.5	1.2	1.9	1.5	1.6	2.6	2.5	1.3
MA	Merrimack	NEMA/WCMA	96.0%	102.7%	104.6%	1.0	0.8	1.2	0.8	1.6	1.1	2.0	2.9	2.5	1.4
MA	North Hampton	WCMA	97.7%	103.2%	104.8%	1.9	1.9	1.9	0.7	2.4	1.8	2.5	3.4	3.4	1.5
MA	Palmer	WCMA	97.7%	103.2%	104.8%	1.9	0.0	1.3	1.9	3.1	1.6	3.7	3.9	2.2	1.1
MA	South Berkshire	WCMA	97.7%	103.2%	104.8%	1.8	1.9	2.1	0.7	2.4	1.8	2.7	4.1	3.3	1.2
MA	Surburban	NEMA	94.7%	102.4%	104.6%	1.0	1.2	1.4	1.1	1.8	1.3	2.2	2.8	3.2	2.0
MA	Uxbridge	SEMA/WCMA	93.6%	102.3%	104.7%	0.3	1.5	1.5	1.7	2.5	1.5	3.4	3.6	2.7	1.0
MA	Webster	WCMA	97.7%	103.2%	104.8%	0.6	2.6	0.3	1.1	2.1	1.3	3.3	3.8	2.3	1.2
MA	Weymouth	SEMA	93.6%	102.3%	104.7%	0.4	0.4	0.9	0.5	1.3	0.7	1.8	3.3	3.8	1.9
MA	Worcester	WCMA	97.7%	103.2%	104.8%	1.4	2.1	1.7	1.5	2.3	1.8	2.4	2.6	2.4	1.6

(1) Zones refer to ISO-NE designations

(2) These first year weather-adjustment values can be applied to actual MW readings for current summer peaks to determine what the weather-adjusted value is for any of the three weather scenarios.

(3) These annual growth percents are under the 90/10 weather scenario and can be applied to the current summer peaks to determine what the growth for each area is.

Year One Weather-Adjustment and Multi-Year Annual Growth Percentages (Summer) **after EE, EV, and EH impacts**

			2022 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg	5-yr avg	5-yr avg
State	PSA	Zone (1)	for 50/50	for 90/10	for 95/5	_2023	_2024	_2025	_2026	_2027	'23 to '27	'28 to '32	'33 to '37	'38 to '42	'43 to '47
MA	Adams	WCMA	97.7%	103.2%	104.8%	2.2	2.0	2.1	1.7	2.5	2.1	3.8	3.8	3.6	2.1
MA	Athol	WCMA	97.7%	103.2%	104.8%	3.9	3.1	3.2	3.2	3.7	3.4	4.2	4.0	2.4	1.1
MA	Attleboro	SEMA	93.6%	102.3%	104.7%	0.8	0.7	1.0	0.7	1.6	0.9	2.3	2.8	2.4	1.2
MA	Brockton	SEMA	93.6%	102.3%	104.7%	0.6	0.8	1.1	0.9	1.8	1.0	2.4	3.2	2.4	1.1
MA	Essex	NEMA	94.7%	102.4%	104.6%	1.2	1.4	1.6	1.3	2.2	1.6	2.7	3.4	2.9	1.3
MA	Fall River	SEMA	93.6%	102.3%	104.7%	0.6	0.6	0.9	0.6	1.6	0.9	2.2	2.5	2.2	1.2
MA	Gardner	WCMA	97.7%	103.2%	104.8%	1.9	1.7	1.9	2.0	2.3	2.0	3.0	3.3	2.3	1.1
MA	Leominster	WCMA	97.7%	103.2%	104.8%	2.0	1.9	2.0	1.5	2.3	1.9	2.5	2.5	2.7	1.7
MA	Marlboro	WCMA	97.7%	103.2%	104.8%	1.3	1.5	1.7	1.3	2.1	1.6	2.0	2.4	2.2	1.4
MA	Merrimack	NEMA/WCMA	96.0%	102.7%	104.6%	1.1	1.3	1.5	1.1	1.9	1.4	2.2	2.6	2.5	1.4
MA	North Hampton	WCMA	97.7%	103.2%	104.8%	2.0	2.0	2.1	1.7	2.5	2.0	2.7	3.0	3.5	1.6
MA	Palmer	WCMA	97.7%	103.2%	104.8%	2.2	2.0	2.2	2.1	2.8	2.3	3.4	3.7	2.3	1.1
MA	South Berkshire	WCMA	97.7%	103.2%	104.8%	1.9	2.0	2.1	1.9	2.5	2.1	3.3	3.9	3.3	1.2
MA	Surburban	NEMA	94.7%	102.4%	104.6%	1.2	1.4	1.6	1.2	2.0	1.5	2.3	2.7	3.2	2.0
MA	Uxbridge	SEMA/WCMA	93.6%	102.3%	104.7%	1.8	2.2	2.3	2.1	2.9	2.2	3.1	3.5	2.8	1.1
MA	Webster	WCMA	97.7%	103.2%	104.8%	1.9	1.8	1.9	1.9	2.4	2.0	3.1	3.6	2.6	1.3
MA	Weymouth	SEMA	93.6%	102.3%	104.7%	0.5	0.7	1.0	0.7	1.5	0.9	2.0	2.9	3.9	1.9
MA	Worcester	WCMA	97.7%	103.2%	104.8%	1.8	2.0	2.1	1.7	2.3	2.0	2.4	2.6	2.2	1.7

(1) Zones refer to ISO-NE designations

(2) These first year weather-adjustment values can be applied to actual MW readings for current summer peaks to determine what the weather-adjusted value is for any of the three weather scenarios.

(3) These annual growth percents are under the 90/10 weather scenario and can be applied to the current summer peaks to determine what the growth for each area is.

Year One Weather-Adjustment and Multi-Year Annual Growth Percentages (WINTER) — **after EE, PV, EV, and EH impacts**

			2021/22 Weather-Adjustments (2)					**Annual Growth Rates (percent**			**5-yr avg**	**5-yr avg**	**5-yr avg**	**5-yr avg**	**5-yr avg**
State	**PSA**	**Zone (1)**	**for 50/50**	**for 10/90**	**for 05/95**	**2022**	**2023**	**2024**	**2025**	**2026**	**'22 to '26**	**'27 to '31**	**'32 to '36**	**'37 to '41**	**'42 to '46**
MA	Adams	WCMA	98.9%	102.7%	103.8%	2.2	2.3	2.5	2.3	3.1	2.5	6.0	7.0	6.0	4.0
MA	Athol	WCMA	98.9%	102.7%	103.8%	4.0	3.5	3.5	3.7	4.4	3.8	6.9	7.5	3.4	1.5
MA	Attleboro	SEMA	99.2%	103.2%	104.3%	1.1	1.2	1.9	1.5	2.7	1.7	4.4	6.4	5.3	2.2
MA	Brockton	SEMA	99.2%	103.2%	104.3%	0.6	1.1	1.9	1.9	2.7	1.6	4.9	7.3	5.4	2.7
MA	Essex	NEMA	99.7%	105.1%	106.6%	1.6	2.0	2.4	2.3	3.5	2.4	4.7	6.9	5.9	2.1
MA	Fall River	SEMA	99.2%	103.2%	104.3%	0.5	0.6	1.2	1.1	2.2	1.1	4.2	6.6	5.3	3.1
MA	Gardner	WCMA	98.9%	102.7%	103.8%	2.3	2.0	2.3	2.5	2.8	2.4	4.6	5.8	4.4	1.6
MA	Leominster	WCMA	98.9%	102.7%	103.8%	2.6	2.9	2.9	2.6	3.7	3.0	5.8	7.8	7.0	2.8
MA	Marlboro	WCMA	98.9%	102.7%	103.8%	1.6	1.9	2.2	2.6	3.8	2.4	2.9	5.0	4.4	1.9
MA	Merrimack	NEMA/WCMA	99.3%	104.0%	105.3%	0.8	1.5	1.9	1.9	2.7	1.7	4.0	6.2	5.4	3.2
MA	Northampton	WCMA	98.9%	102.7%	103.8%	2.1	2.3	2.6	2.3	3.2	2.5	4.4	6.6	6.7	3.2
MA	Palmer	WCMA	98.9%	102.7%	103.8%	2.4	2.3	2.7	2.8	3.6	2.7	5.4	6.7	4.2	1.8
MA	South Berkshire	WCMA	98.9%	102.7%	103.8%	2.0	2.2	2.6	2.7	3.2	2.6	5.5	7.2	5.6	2.0
MA	Surburban	NEMA	99.7%	105.1%	106.6%	1.3	1.7	2.1	2.0	2.8	2.0	4.0	6.6	6.8	4.2
MA	Uxbridge	SEMA/WCMA	99.2%	103.2%	104.3%	2.5	3.3	3.7	4.0	5.8	3.9	5.2	7.3	5.1	1.8
MA	Webster	WCMA	98.9%	102.7%	103.8%	2.3	2.2	2.7	2.8	3.5	2.7	4.7	6.3	4.6	1.8
MA	Weymouth	SEMA	99.2%	103.2%	104.3%	0.4	0.9	1.6	1.5	2.1	1.3	4.1	7.4	8.1	3.7
MA	Worcester	WCMA	98.9%	102.7%	103.8%	1.8	2.0	2.4	2.1	2.7	2.2	3.7	5.6	5.2	3.1

(1) Zones refer to ISO-NE designations

(2) These first year weather-adjustment values can be applied to actual MW readings for current winter peaks to determine what the weather-adjusted value is for any of the three weather scenarios.

(3) These annual growth percents are under the 90/10 weather scenario and can be applied to the current summer peaks to determine what the growth for each area is.

Appendix C: Study Areas

The Company provides peak load growth forecast for the 46 study areas in its Massachusetts service territory. The forecasting process leverages regional information to allocates the system-level load growth projection and outlook on distributed energy resources (DER) to the feeder level. The allocations of load growth, energy efficiency, and medium- and heavy-duty electric vehicle growth use regional energy growth information. The allocations on solar PV, light-duty electric vehicles, and electric heat pumps use demographic information, heating fuel type information, and land availability. The feeder level forecasts are then aggregated to the study area level, and a year-over-year peak load growth rate is generated and presented in the tables below.

Year One Weather-Adjustment (90/10) and Multi-Year Annual Growth Percentage (Summer), after EE, PV, EV, and EH impacts

Study Area	Weather Adjustment	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Adams/Deerfield	103.2%	2.0%	1.8%	2.0%	1.4%	2.4%	2.6%	3.3%	4.2%	3.3%	4.3%	4.6%	4.8%	2.9%	3.6%	3.4%	3.8%	3.3%	4.0%	3.5%	2.9%	2.7%	2.9%	1.8%	1.8%	1.2%	0.6%	1.2%	0.7%
Amesbury Newburyport	102.4%	0.9%	0.1%	0.1%	0.3%	2.0%	1.9%	2.2%	2.4%	3.0%	3.0%	3.0%	3.0%	3.5%	3.2%	1.9%	3.2%	3.5%	2.9%	2.0%	1.2%	1.1%	1.3%	1.0%	1.3%	0.9%	0.3%	1.2%	0.9%
Attleboro	102.3%	0.4%	0.1%	0.8%	0.3%	0.4%	1.7%	1.9%	2.1%	3.5%	4.2%	4.0%	2.5%	3.5%	3.6%	3.1%	2.9%	2.6%	2.9%	2.2%	1.5%	1.2%	1.4%	0.8%	1.3%	1.0%	0.4%	1.3%	0.9%
Ayer Clinton	103.2%	-0.1%	2.1%	1.7%	-0.4%	2.0%	3.5%	1.7%	-0.2%	3.3%	2.9%	3.5%	3.7%	3.1%	2.6%	2.3%	2.9%	3.1%	3.9%	2.7%	1.8%	1.5%	1.7%	1.3%	1.6%	0.9%	0.4%	1.2%	0.9%
Barre-Athol	103.2%	1.7%	2.8%	-0.3%	3.1%	3.7%	3.9%	4.4%	3.0%	5.0%	4.3%	5.4%	6.3%	3.7%	3.6%	3.6%	3.5%	2.9%	3.0%	1.8%	1.3%	1.1%	1.3%	1.1%	1.3%	1.0%	0.4%	1.3%	1.0%
Beverly	102.4%	-0.4%	1.2%	1.5%	0.9%	1.8%	0.3%	2.0%	2.0%	2.6%	3.1%	3.3%	3.2%	2.7%	4.2%	2.3%	4.3%	3.0%	2.9%	2.0%	1.6%	1.5%	1.6%	1.4%	1.7%	1.1%	0.4%	1.2%	0.9%
Billerica	103.2%	1.2%	0.3%	1.4%	1.1%	1.7%	1.8%	2.2%	2.4%	2.6%	2.5%	2.7%	3.1%	3.0%	3.2%	2.9%	2.8%	3.4%	3.0%	2.1%	1.2%	1.0%	1.2%	1.0%	1.2%	0.9%	0.4%	1.2%	0.9%
Bridgewater	102.3%	0.1%	-0.9%	0.8%	0.8%	1.5%	1.7%	2.2%	2.7%	3.7%	4.0%	4.3%	4.5%	3.7%	4.1%	2.9%	3.0%	2.5%	3.5%	1.7%	1.1%	1.0%	1.2%	1.0%	1.2%	0.9%	0.3%	1.2%	0.9%
Brockton	102.3%	0.1%	0.4%	0.8%	0.4%	0.7%	1.6%	1.7%	2.1%	2.5%	2.7%	3.5%	3.9%	3.0%	3.9%	2.7%	3.0%	2.9%	2.9%	1.8%	1.2%	1.1%	1.3%	1.1%	1.4%	1.0%	0.4%	1.3%	0.9%
Brockton NW / Randolph	102.3%	-0.8%	0.3%	0.8%	0.5%	1.5%	1.5%	1.8%	2.0%	2.9%	3.6%	3.9%	3.6%	3.1%	3.9%	3.0%	3.0%	2.7%	3.2%	2.3%	1.6%	1.3%	1.4%	1.1%	1.3%	0.9%	0.4%	1.2%	0.9%
Cape Ann	102.4%	1.2%	1.3%	1.5%	1.2%	2.1%	2.1%	3.0%	3.1%	3.4%	3.9%	4.2%	4.0%	4.0%	4.4%	3.6%	4.7%	3.9%	3.1%	1.7%	1.3%	1.1%	1.2%	1.0%	1.2%	0.9%	0.4%	1.1%	0.8%
Chelmsford Westford	103.2%	1.0%	0.4%	1.4%	1.1%	1.9%	1.9%	2.0%	2.2%	2.5%	2.5%	2.3%	2.6%	2.7%	3.9%	2.7%	3.5%	2.6%	2.7%	1.7%	1.7%	1.4%	1.5%	1.3%	1.3%	1.5%	0.8%	1.6%	0.8%
Dracut	102.7%	1.1%	1.2%	1.4%	1.0%	2.0%	-2.2%	2.8%	3.2%	3.4%	3.4%	3.5%	4.2%	3.2%	3.7%	3.4%	2.4%	3.2%	3.3%	1.7%	1.5%	1.4%	1.5%	1.3%	1.3%	1.0%	0.4%	1.2%	0.9%
Everett Malden Medford	102.4%	1.0%	1.2%	1.5%	1.1%	1.8%	1.7%	1.9%	2.0%	2.4%	2.2%	2.2%	2.6%	2.6%	2.7%	2.8%	4.6%	3.5%	4.6%	3.2%	2.7%	2.6%	2.5%	2.0%	2.0%	1.4%	0.8%	1.3%	1.0%
Fall River	102.3%	0.4%	0.4%	0.6%	0.3%	1.2%	1.2%	1.5%	1.7%	1.9%	1.8%	2.0%	2.6%	1.5%	2.3%	2.6%	2.6%	2.4%	2.6%	2.0%	1.3%	1.2%	1.4%	1.2%	1.5%	1.0%	0.4%	1.4%	1.0%
Gardner Winchendon	103.2%	-2.2%	1.6%	1.3%	1.6%	2.1%	5.7%	0.6%	2.1%	3.8%	4.0%	3.7%	5.6%	2.9%	3.4%	3.0%	2.9%	1.1%	3.3%	1.3%	1.3%	1.4%	1.2%	1.0%	1.3%	0.9%	0.4%	1.2%	1.2%
Hanover	102.3%	0.5%	0.3%	1.1%	0.7%	1.3%	1.6%	1.9%	2.0%	3.0%	4.3%	4.2%	3.4%	4.0%	3.8%	2.7%	2.9%	2.9%	3.5%	1.9%	1.4%	1.0%	1.1%	0.9%	1.3%	0.9%	0.4%	1.0%	0.9%
Haverhill	102.4%	1.0%	0.4%	1.1%	0.8%	-0.3%	1.7%	2.0%	2.1%	2.2%	2.4%	3.1%	3.7%	2.4%	2.9%	2.5%	2.8%	2.5%	3.3%	1.9%	2.8%	2.3%	2.9%	2.3%	2.3%	1.7%	0.9%	1.6%	1.1%
Hopedale East	102.3%	-0.3%	-0.1%	0.7%	0.3%	-0.7%	1.7%	1.6%	2.0%	3.0%	3.0%	3.0%	3.1%	3.3%	2.7%	2.6%	3.6%	2.6%	2.9%	1.9%	0.6%	1.1%	1.3%	1.1%	1.2%	1.0%	0.1%	1.3%	1.1%
Hopedale West	102.3%	0.1%	1.5%	1.4%	1.7%	2.4%	2.9%	2.5%	3.3%	4.0%	4.1%	4.2%	3.8%	3.2%	3.6%	3.3%	3.0%	2.5%	4.2%	2.2%	1.4%	1.0%	1.4%	1.0%	1.2%	0.9%	0.4%	1.2%	1.1%
Lawrence	102.7%	1.0%	1.2%	1.3%	0.8%	1.6%	1.7%	1.7%	1.7%	1.8%	1.8%	1.8%	2.1%	1.5%	2.7%	1.6%	2.2%	1.8%	2.4%	1.7%	1.2%	1.1%	1.4%	1.0%	1.5%	1.1%	0.4%	1.3%	1.1%
Leominster	103.2%	1.8%	1.8%	1.9%	1.4%	1.5%	2.5%	1.4%	2.5%	2.7%	2.6%	2.7%	3.2%	2.1%	2.4%	2.0%	2.6%	2.8%	2.9%	3.4%	2.5%	2.3%	2.3%	1.7%	1.9%	1.3%	0.7%	1.5%	1.3%
Lowell	103.2%	1.1%	1.0%	1.1%	0.8%	1.5%	1.5%	1.5%	1.6%	1.7%	1.7%	2.1%	2.0%	1.4%	3.8%	1.7%	2.2%	2.0%	2.3%	1.7%	3.0%	3.7%	3.1%	2.6%	2.6%	2.2%	1.6%	2.5%	1.6%
Lynn	102.4%	1.0%	1.2%	1.4%	1.0%	1.7%	1.7%	1.8%	1.9%	2.0%	2.0%	2.2%	2.2%	1.6%	2.5%	1.7%	2.4%	2.1%	2.3%	1.8%	1.4%	2.3%	1.6%	1.4%	1.6%	1.2%	0.6%	1.4%	1.1%
Marlboro	103.2%	1.3%	1.5%	1.5%	1.2%	1.8%	1.9%	1.4%	2.0%	1.2%	1.4%	2.4%	3.9%	2.4%	2.8%	1.5%	3.4%	1.9%	3.4%	2.3%	1.7%	1.5%	1.7%	1.0%	1.4%	1.0%	0.4%	1.3%	1.4%
Melrose Saugus	102.4%	1.1%	1.2%	1.5%	1.2%	1.9%	1.8%	2.1%	2.2%	2.5%	2.6%	2.8%	3.0%	3.2%	3.9%	2.8%	3.9%	3.1%	4.0%	2.3%	1.7%	1.7%	1.9%	1.5%	1.7%	1.3%	0.7%	1.3%	0.9%
Methuen	102.7%	1.1%	0.8%	1.4%	-1.4%	1.8%	1.6%	0.0%	2.7%	2.8%	2.8%	3.0%	3.5%	2.9%	3.1%	2.8%	3.0%	2.8%	3.0%	3.5%	2.6%	1.9%	1.7%	1.4%	1.8%	1.5%	0.9%	1.6%	1.0%
Millbury-Grafton	103.2%	0.6%	2.7%	-0.1%	1.5%	2.1%	5.1%	0.9%	2.5%	3.8%	4.1%	3.6%	3.9%	3.3%	4.1%	3.2%	3.6%	2.4%	3.5%	1.7%	1.0%	1.1%	1.2%	0.8%	1.5%	1.1%	0.6%	1.3%	2.0%
Monson-Palmer-Longmeadow	103.2%	1.7%	-0.1%	0.6%	2.2%	2.9%	3.1%	3.5%	3.7%	4.0%	4.1%	5.0%	3.9%	3.4%	4.2%	3.2%	3.2%	2.6%	2.5%	1.5%	1.0%	1.0%	1.3%	1.0%	1.2%	0.9%	0.4%	1.2%	0.9%
Nantucket	99.2%	2.2%	1.9%	1.8%	2.0%	2.3%	2.3%	2.2%	2.2%	2.4%	2.4%	2.4%	2.5%	2.4%	2.4%	2.3%	2.2%	2.1%	2.1%	1.7%	1.5%	1.4%	1.2%	1.1%	1.0%	0.9%	0.8%	0.7%	0.7%
North Andover	102.7%	1.1%	1.2%	1.4%	1.1%	1.7%	1.6%	1.8%	2.0%	2.3%	0.8%	2.3%	2.7%	2.5%	2.5%	2.4%	2.4%	2.4%	2.6%	1.7%	1.3%	1.1%	1.3%	1.0%	1.3%	0.9%	0.4%	1.2%	0.9%
North Lowell	103.2%	1.2%	1.2%	1.4%	1.1%	1.9%	1.8%	2.0%	2.2%	2.4%	2.5%	2.5%	2.8%	2.2%	3.1%	3.2%	3.1%	2.9%	3.8%	2.6%	2.1%	1.8%	1.5%	1.2%	1.5%	1.3%	0.5%	1.7%	1.4%
Northampton-S berkshire	103.2%	1.9%	1.9%	1.9%	0.5%	2.5%	1.7%	2.7%	3.3%	2.3%	3.0%	3.7%	4.6%	2.7%	4.3%	3.1%	4.4%	3.6%	3.3%	2.6%	2.0%	1.8%	1.7%	1.4%	1.3%	0.9%	0.4%	1.2%	0.9%
Pepperell Dunstable	103.2%	0.9%	1.3%	1.7%	-2.9%	2.9%	3.2%	3.8%	4.0%	4.0%	4.0%	3.6%	2.9%	6.4%	4.2%	2.1%	3.5%	3.5%	2.4%	1.2%	0.9%	0.8%	1.0%	0.9%	1.2%	0.8%	0.4%	1.1%	0.8%
Quincy	102.3%	0.3%	0.3%	0.8%	0.4%	1.2%	1.2%	1.4%	1.5%	1.9%	2.1%	2.3%	2.8%	2.3%	3.3%	2.5%	3.4%	5.6%	4.9%	3.9%	3.2%	2.8%	2.5%	2.2%	2.2%	1.4%	0.7%	1.2%	0.9%
Revere Winthrop	102.4%	0.9%	1.2%	1.4%	1.1%	2.0%	1.9%	2.4%	2.4%	2.7%	2.2%	2.1%	2.7%	1.8%	2.3%	3.2%	3.0%	3.9%	3.8%	3.0%	2.4%	3.6%	3.8%	3.4%	3.5%	2.6%	1.7%	2.2%	1.6%
Salem Swampscott	102.4%	1.1%	1.3%	1.5%	1.1%	1.8%	1.8%	2.0%	2.1%	2.5%	2.7%	3.0%	3.6%	3.0%	3.6%	2.7%	3.3%	4.0%	4.0%	3.0%	2.4%	2.2%	2.3%	1.8%	1.7%	1.1%	0.5%	1.2%	0.8%
Scituate	102.3%	0.5%	0.9%	1.5%	1.2%	2.1%	1.8%	2.2%	2.3%	3.1%	3.1%	2.0%	2.7%	5.8%	3.2%	1.4%	1.9%	1.9%	2.2%	1.3%	0.9%	0.8%	1.1%	0.9%	1.2%	0.9%	0.3%	1.2%	0.9%
Somerset	102.3%	0.2%	0.5%	0.8%	0.5%	2.0%	0.9%	2.9%	3.5%	4.1%	4.7%	4.8%	3.3%	3.2%	5.3%	2.6%	2.2%	2.1%	2.6%	1.4%	1.0%	0.9%	1.2%	1.0%	1.3%	0.9%	0.4%	1.2%	0.9%
Spencer-Rutland	103.2%	0.9%	1.7%	-0.6%	-0.1%	1.7%	5.2%	-1.1%	4.1%	5.2%	4.8%	4.7%	5.8%	3.8%	4.5%	4.3%	3.6%	3.2%	3.6%	1.4%	1.2%	1.0%	1.0%	0.9%	1.1%	0.8%	0.4%	1.1%	0.9%
Tewksbury	102.7%	1.1%	1.2%	0.8%	0.8%	1.9%	1.9%	2.1%	2.3%	2.5%	2.7%	2.8%	2.8%	3.1%	3.8%	2.3%	2.3%	2.6%	2.7%	2.0%	1.4%	1.3%	1.1%	0.9%	1.3%	0.9%	0.4%	1.2%	0.9%
Topsfield	102.4%	1.0%	1.6%	2.0%	2.3%	2.9%	2.9%	3.1%	2.9%	3.0%	2.1%	1.8%	1.6%	5.5%	0.6%	1.6%	2.1%	2.1%	2.4%	1.3%	1.0%	0.9%	1.2%	0.9%	1.2%	0.8%	0.4%	1.2%	0.9%
Webster Southbridge Charlton	103.2%	1.0%	2.4%	-1.4%	1.0%	2.1%	3.9%	1.1%	3.4%	4.0%	4.0%	3.4%	5.7%	2.8%	3.7%	3.3%	3.1%	1.7%	3.6%	1.3%	1.8%	1.5%	1.9%	1.4%	1.5%	1.1%	0.5%	1.3%	1.6%
Weymouth Holbrook	102.3%	0.5%	0.6%	1.0%	0.6%	1.5%	1.5%	1.7%	2.1%	1.6%	4.2%	4.1%	4.0%	4.3%	4.2%	3.3%	3.2%	3.9%	4.4%	2.8%	2.1%	1.7%	1.6%	1.2%	1.4%	0.8%	0.3%	1.1%	0.9%
Worcester North	103.2%	1.3%	2.1%	1.5%	1.5%	2.3%	2.7%	1.8%	2.3%	2.4%	2.5%	2.9%	3.4%	2.1%	2.9%	2.0%	2.4%	3.2%	3.2%	2.3%	1.7%	1.4%	1.7%	1.6%	1.7%	1.2%	0.6%	1.4%	0.9%
Worcester South	103.2%	1.5%	2.1%	1.9%	1.6%	2.2%	2.2%	2.0%	2.3%	2.3%	2.2%	2.4%	2.6%	2.3%	2.4%	1.8%	2.3%	2.0%	2.3%	1.7%	1.5%	1.3%	1.7%	1.7%	1.9%	2.5%	0.9%	1.7%	1.3%

Year One Weather-Adjustment and Multi-Year Annual Growth Percentage (Summer), after EE, EV, and EH impacts																														
Study Area	Weather Adjustment (90/10)	Weather Adjustment (50/50)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Adams/Deerfield	103.2%	97.7%	2.3%	2.0%	2.1%	1.7%	2.5%	2.7%	3.4%	4.3%	4.2%	4.0%	4.1%	4.4%	2.7%	4.1%	3.4%	3.8%	3.4%	3.9%	3.5%	3.1%	2.8%	2.9%	1.8%	1.8%	1.2%	0.7%	1.2%	0.9%
Amesbury Newburyport	102.4%	94.7%	1.1%	1.3%	1.6%	1.2%	2.0%	1.9%	2.2%	2.3%	2.7%	2.6%	2.6%	2.7%	3.0%	3.2%	1.7%	2.9%	3.9%	3.2%	2.0%	1.3%	1.1%	1.3%	1.0%	1.3%	0.9%	0.4%	1.2%	0.9%
Attleboro	102.3%	93.6%	0.7%	0.6%	1.0%	0.7%	1.7%	1.8%	2.0%	2.2%	3.2%	3.6%	3.5%	2.8%	3.0%	3.7%	3.1%	2.9%	2.9%	2.9%	2.2%	1.5%	1.2%	1.4%	1.1%	1.3%	1.0%	0.4%	1.2%	0.9%
Ayer Clinton	103.2%	97.7%	2.2%	2.0%	2.0%	1.5%	2.2%	2.2%	2.5%	2.7%	2.8%	2.5%	3.0%	3.0%	2.6%	2.3%	2.2%	2.5%	2.6%	4.4%	2.6%	1.8%	1.5%	1.7%	1.3%	1.5%	0.9%	0.4%	1.2%	0.9%
Barre-Athol	103.2%	97.7%	3.9%	3.1%	3.2%	3.3%	3.7%	3.5%	4.2%	4.9%	4.4%	3.9%	4.8%	5.2%	3.2%	3.2%	3.7%	3.4%	2.8%	2.9%	1.8%	1.3%	1.1%	1.3%	1.1%	1.3%	1.0%	0.4%	1.3%	1.0%
Beverly	102.4%	94.7%	1.2%	1.3%	1.5%	1.2%	1.9%	1.8%	2.0%	2.0%	2.2%	2.7%	2.8%	2.8%	2.3%	3.7%	2.0%	3.7%	3.4%	2.9%	2.0%	1.6%	1.5%	1.6%	1.4%	1.7%	1.1%	0.4%	1.2%	0.9%
Billerica	103.2%	97.7%	1.2%	1.2%	1.5%	1.2%	2.0%	1.9%	2.2%	2.5%	2.6%	2.6%	2.7%	3.2%	2.4%	2.9%	2.4%	2.6%	4.1%	3.1%	2.1%	1.3%	1.0%	1.2%	1.0%	1.2%	0.9%	0.4%	1.2%	0.9%
Bridgewater	102.3%	93.6%	0.6%	0.8%	1.0%	1.0%	1.8%	1.8%	2.3%	2.6%	3.2%	3.4%	3.7%	3.9%	3.9%	4.4%	2.9%	3.0%	2.6%	3.5%	1.8%	1.2%	1.0%	1.3%	1.0%	1.2%	0.9%	0.4%	1.2%	0.9%
Brockton	102.3%	93.6%	0.5%	0.6%	0.9%	0.6%	1.5%	1.7%	1.8%	2.2%	2.5%	2.8%	2.9%	3.3%	2.6%	3.5%	3.1%	3.0%	2.9%	3.0%	1.8%	1.2%	1.1%	1.3%	1.1%	1.4%	1.0%	0.4%	1.3%	0.9%
Brockton NW / Randolph	102.3%	93.6%	0.6%	0.8%	1.0%	0.7%	1.6%	1.6%	1.9%	2.1%	2.5%	3.1%	3.3%	3.2%	2.7%	4.0%	3.0%	3.0%	2.7%	3.3%	2.3%	1.6%	1.3%	1.4%	1.1%	1.3%	0.9%	0.4%	1.2%	0.9%
Cape Ann	102.4%	94.7%	1.3%	1.5%	1.7%	1.4%	2.2%	2.3%	3.1%	3.2%	3.5%	3.9%	3.8%	3.5%	4.1%	4.5%	3.6%	4.8%	3.9%	3.1%	1.8%	1.4%	1.1%	1.2%	1.0%	1.3%	0.9%	0.4%	1.1%	0.8%
Chelmsford Westford	103.2%	97.7%	1.1%	1.3%	1.5%	1.2%	1.9%	2.0%	2.1%	2.2%	2.5%	2.6%	2.3%	2.6%	2.7%	3.3%	2.3%	3.1%	3.2%	2.8%	1.8%	1.7%	1.4%	1.5%	1.3%	1.6%	1.5%	0.8%	1.6%	1.1%
Dracut	102.7%	95.9%	1.2%	1.3%	1.6%	1.3%	2.1%	2.1%	2.4%	2.7%	2.9%	2.9%	3.0%	3.7%	2.8%	3.3%	3.8%	3.4%	3.2%	3.3%	2.2%	1.4%	1.3%	1.5%	1.3%	1.3%	1.0%	0.4%	1.2%	0.9%
Everett Malden Medford	102.4%	94.7%	1.2%	1.4%	1.6%	1.2%	1.9%	1.8%	2.1%	2.1%	2.4%	2.3%	2.3%	2.7%	2.7%	2.8%	2.2%	4.0%	3.9%	4.6%	3.2%	2.7%	2.6%	2.5%	2.0%	2.0%	1.4%	0.8%	1.3%	1.0%
Fall River	102.3%	93.6%	0.6%	0.6%	0.8%	0.4%	1.3%	1.4%	1.6%	1.8%	2.0%	1.8%	2.0%	2.7%	1.6%	2.4%	1.8%	2.4%	2.1%	2.4%	1.8%	1.2%	1.1%	1.3%	1.1%	1.4%	1.0%	0.3%	1.3%	0.9%
Gardner Winchendon	103.2%	97.7%	2.1%	1.8%	1.9%	2.1%	2.3%	2.4%	2.7%	2.9%	3.3%	3.5%	3.8%	3.6%	2.6%	3.2%	2.6%	3.4%	2.8%	2.8%	1.7%	1.2%	1.4%	1.2%	1.0%	1.3%	0.9%	0.4%	1.2%	0.9%
Hanover	102.3%	93.6%	0.6%	0.8%	1.3%	1.0%	1.9%	1.7%	2.0%	2.1%	3.1%	3.8%	3.6%	3.0%	4.0%	3.8%	2.7%	3.0%	3.0%	3.5%	1.9%	1.4%	1.0%	1.2%	0.9%	1.3%	0.9%	0.4%	1.2%	0.9%
Haverhill	102.4%	94.7%	1.1%	1.2%	1.4%	1.0%	1.7%	1.7%	2.0%	2.1%	2.2%	2.4%	2.6%	3.2%	2.1%	2.6%	2.2%	2.5%	2.2%	3.0%	2.9%	2.8%	2.3%	2.9%	2.3%	2.3%	1.7%	0.9%	1.6%	1.1%
Hopedale East	102.3%	93.6%	0.8%	0.7%	1.1%	0.6%	1.5%	1.4%	1.7%	2.1%	2.5%	2.5%	2.6%	2.6%	2.7%	2.3%	2.2%	3.9%	2.6%	2.9%	1.9%	1.3%	1.1%	1.3%	1.1%	1.4%	1.0%	0.3%	1.3%	0.9%
Hopedale West	102.3%	93.6%	1.8%	2.2%	2.3%	2.1%	2.9%	2.6%	2.7%	2.9%	3.5%	3.9%	3.7%	3.3%	3.4%	3.4%	3.7%	3.3%	3.1%	4.0%	2.2%	1.5%	1.3%	1.3%	1.0%	1.2%	0.9%	0.4%	1.2%	0.9%
Lawrence	102.7%	95.9%	1.1%	1.2%	1.4%	0.9%	1.7%	1.7%	1.8%	1.7%	1.8%	1.8%	1.8%	2.1%	1.6%	2.8%	1.6%	2.3%	2.0%	2.2%	1.7%	1.2%	1.1%	1.4%	1.2%	1.5%	1.1%	0.4%	1.3%	1.0%
Leominster	103.2%	97.7%	1.8%	1.9%	2.1%	1.5%	2.3%	2.1%	2.3%	2.5%	2.7%	2.6%	2.8%	3.0%	2.2%	2.4%	2.0%	2.7%	2.3%	2.5%	3.0%	2.2%	3.1%	2.3%	1.8%	1.9%	1.3%	0.7%	1.5%	1.0%
Lowell	103.2%	97.7%	1.1%	1.1%	1.2%	0.9%	1.6%	1.5%	1.6%	1.6%	1.8%	1.7%	2.2%	2.1%	1.4%	3.8%	1.8%	2.3%	2.1%	2.3%	1.7%	3.0%	2.5%	2.7%	3.8%	2.6%	2.2%	1.6%	2.5%	1.6%
Lynn	102.4%	94.7%	1.1%	1.3%	1.5%	1.1%	1.8%	1.7%	1.9%	2.0%	2.0%	2.1%	2.3%	2.3%	1.6%	2.6%	1.8%	2.4%	2.1%	2.3%	1.9%	1.4%	1.3%	1.5%	1.3%	1.5%	1.1%	0.5%	1.3%	1.0%
Marlboro	103.2%	97.7%	1.4%	1.5%	1.7%	1.3%	2.1%	1.7%	1.8%	2.0%	2.3%	2.4%	2.4%	2.5%	2.4%	2.9%	1.8%	2.6%	2.3%	2.8%	2.0%	1.5%	1.3%	1.5%	2.2%	1.4%	1.0%	0.4%	1.3%	0.9%
Melrose Saugus	102.4%	94.7%	1.2%	1.4%	1.6%	1.3%	2.0%	2.0%	2.2%	2.3%	2.6%	2.7%	3.0%	3.1%	2.8%	3.5%	2.4%	4.3%	3.2%	4.0%	2.3%	1.7%	1.7%	1.9%	1.5%	1.8%	1.3%	0.7%	1.3%	0.9%
Methuen	102.7%	95.9%	1.2%	1.3%	1.5%	1.1%	1.9%	1.8%	2.1%	2.3%	2.5%	2.5%	2.6%	3.1%	2.5%	2.7%	2.4%	2.7%	2.5%	3.6%	3.4%	2.5%	1.9%	1.7%	1.4%	1.8%	1.4%	0.9%	1.6%	1.0%
Millbury-Grafton	103.2%	97.7%	1.9%	2.0%	2.2%	1.9%	2.5%	2.6%	2.9%	2.8%	3.3%	3.6%	3.5%	3.0%	2.9%	3.8%	3.4%	3.6%	3.4%	3.0%	1.7%	1.2%	1.1%	1.2%	1.2%	1.5%	1.1%	0.6%	1.3%	0.9%
Monson-Palmer-Longmeadow	103.2%	97.7%	2.2%	2.0%	2.2%	2.1%	2.8%	2.9%	3.2%	3.3%	3.7%	3.8%	4.4%	3.5%	3.0%	4.5%	3.3%	3.2%	2.7%	2.8%	1.6%	1.1%	1.0%	1.3%	1.0%	1.2%	0.9%	0.4%	1.2%	0.9%
Nantucket	99.2%	89.1%	2.3%	2.0%	1.8%	2.1%	2.3%	2.3%	2.2%	2.1%	2.1%	2.1%	2.1%	2.1%	2.0%	2.0%	2.0%	2.0%	2.0%	1.9%	1.6%	1.5%	1.3%	1.2%	1.1%	1.0%	0.9%	0.8%	0.7%	0.6%
North Andover	102.7%	95.9%	1.2%	1.3%	1.5%	1.1%	1.8%	1.7%	1.8%	2.1%	2.3%	2.2%	2.3%	2.7%	2.5%	2.5%	1.7%	2.6%	2.1%	2.3%	1.6%	1.1%	1.0%	1.2%	0.9%	1.3%	0.9%	0.3%	1.2%	0.9%
North Lowell	103.2%	97.7%	1.3%	1.3%	1.5%	1.1%	2.0%	1.9%	2.1%	2.3%	2.5%	2.5%	2.6%	2.9%	2.3%	3.2%	2.5%	2.8%	3.5%	3.8%	2.6%	2.1%	1.9%	1.5%	1.3%	1.5%	1.3%	0.5%	1.7%	1.4%
Northampton-S berkshire	103.2%	97.7%	2.0%	2.0%	2.1%	1.8%	2.5%	2.6%	2.7%	3.3%	3.1%	3.3%	3.9%	4.0%	2.3%	3.8%	2.7%	5.6%	3.7%	3.7%	2.5%	1.9%	1.8%	1.7%	1.4%	1.3%	0.9%	0.4%	1.2%	0.9%
Pepperell Dunstable	103.2%	97.7%	1.0%	1.5%	1.9%	1.7%	2.6%	2.8%	3.3%	3.4%	3.4%	3.5%	3.2%	2.6%	6.2%	4.2%	3.7%	3.4%	3.3%	2.4%	1.2%	0.9%	0.8%	1.0%	0.9%	1.2%	0.8%	0.3%	1.1%	0.8%
Quincy	102.3%	93.6%	0.5%	0.6%	0.9%	0.6%	1.4%	1.4%	1.5%	1.6%	2.0%	2.2%	2.4%	2.9%	2.4%	2.8%	2.1%	3.0%	5.9%	4.9%	3.9%	3.2%	2.8%	2.5%	2.2%	2.2%	1.4%	0.7%	1.2%	0.9%
Revere Winthrop	102.4%	94.7%	1.1%	1.3%	1.6%	1.2%	2.1%	2.1%	2.5%	2.5%	2.8%	2.3%	2.3%	2.8%	1.9%	2.3%	2.4%	2.7%	3.5%	4.4%	3.0%	2.4%	3.6%	3.8%	3.4%	3.4%	2.6%	1.7%	2.2%	1.6%
Salem Swampscott	102.4%	94.7%	1.2%	1.4%	1.6%	1.3%	2.0%	1.9%	2.1%	2.2%	2.6%	2.7%	3.0%	3.6%	2.6%	3.3%	2.4%	3.6%	4.0%	4.0%	3.0%	2.4%	2.2%	2.3%	1.8%	1.7%	1.1%	0.5%	1.2%	0.8%
Scituate	102.3%	93.6%	0.6%	1.0%	1.6%	1.3%	2.2%	2.1%	2.2%	2.4%	3.2%	3.1%	2.1%	2.3%	5.6%	3.3%	1.5%	2.0%	1.9%	2.3%	1.3%	0.9%	0.8%	1.1%	0.9%	1.3%	0.9%	0.3%	1.2%	0.9%
Somerset	102.3%	93.6%	0.6%	0.7%	1.0%	0.9%	2.3%	2.3%	2.8%	2.9%	3.6%	4.0%	4.1%	3.5%	3.2%	5.3%	2.6%	2.4%	2.2%	2.6%	1.4%	1.1%	0.9%	1.2%	1.0%	1.3%	0.9%	0.4%	1.2%	0.9%
Spencer-Rutland	103.2%	97.7%	1.8%	1.3%	1.5%	2.0%	2.2%	2.4%	3.1%	3.3%	4.5%	4.1%	4.3%	4.4%	4.1%	4.4%	4.2%	3.9%	3.1%	3.3%	1.6%	1.1%	0.9%	1.0%	0.9%	1.1%	0.8%	0.4%	1.1%	0.9%
Tewksbury	102.7%	95.9%	1.1%	1.3%	1.5%	1.2%	1.9%	1.9%	2.1%	2.3%	2.5%	2.7%	2.8%	2.8%	3.1%	2.9%	2.0%	2.1%	3.3%	2.8%	2.1%	1.4%	1.3%	1.1%	1.0%	1.3%	0.9%	0.4%	1.2%	0.9%
Topsfield	102.4%	94.7%	1.0%	1.7%	2.1%	2.4%	3.0%	2.9%	3.2%	2.9%	3.1%	2.1%	1.8%	1.6%	4.9%	4.3%	1.6%	2.1%	2.1%	2.3%	1.4%	1.0%	0.9%	1.2%	0.9%	1.2%	0.8%	0.3%	1.2%	0.9%
Webster Southbridge Charlton	103.2%	97.7%	2.1%	1.9%	2.0%	1.7%	2.5%	2.5%	2.7%	3.0%	3.4%	3.5%	3.8%	3.6%	2.7%	3.4%	3.7%	3.3%	2.9%	3.0%	1.8%	1.7%	1.5%	1.8%	1.4%	1.5%	1.1%	0.5%	1.3%	0.9%
Weymouth Holbrook	102.3%	93.6%	0.7%	0.9%	1.2%	0.8%	1.6%	1.7%	1.9%	2.2%	2.7%	3.6%	3.6%	3.5%	4.2%	4.3%	3.3%	3.3%	3.9%	4.4%	2.8%	2.1%	1.7%	1.6%	1.2%	1.4%	0.8%	0.3%	1.1%	0.9%
Worcester North	103.2%	97.7%	1.7%	2.0%	2.1%	1.7%	2.4%	2.2%	2.3%	2.3%	2.4%	2.5%	3.0%	3.1%	2.1%	2.9%	2.1%	2.4%	2.6%	3.0%	2.1%	1.5%	2.1%	1.7%	1.4%	1.7%	1.2%	0.6%	1.4%	1.1%
Worcester South	103.2%	97.7%	1.8%	2.0%	2.1%	1.6%	2.3%	2.1%	2.2%	2.3%	2.3%	2.3%	2.4%	2.6%	2.3%	2.5%	1.9%	2.4%	2.1%	2.3%	1.7%	1.5%	1.3%	1.7%	1.7%	1.9%	1.4%	0.7%	1.6%	1.3%

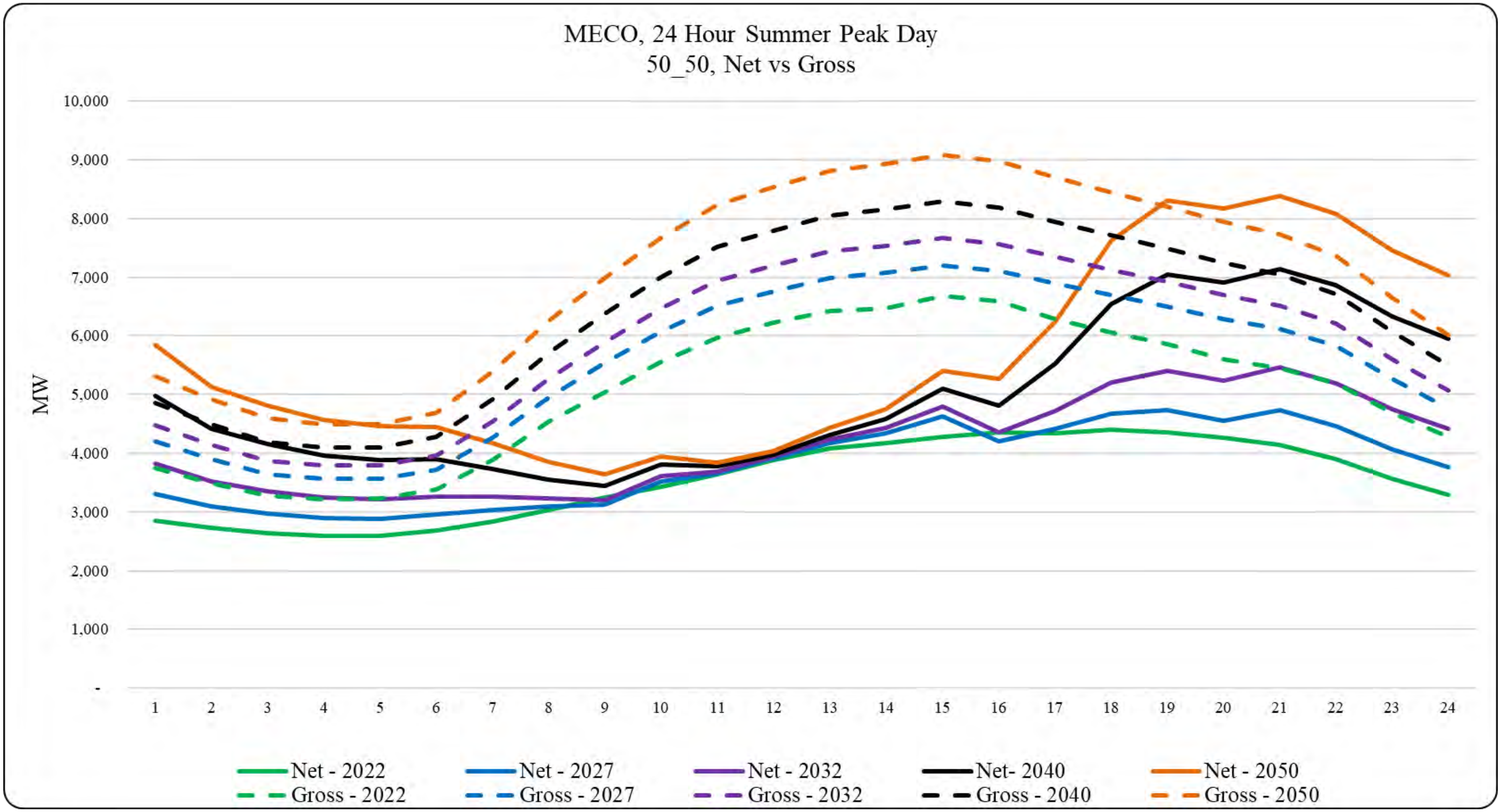
Year One Weather-Adjustment (90/10) and Multi-Year Annual Growth Percentage (Winter), after EE, PV, EV, and EH impacts																														
Study Area	Weather Adjustment	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Adams/Deerfield	102.7%	2.3%	2.3%	2.5%	2.2%	3.1%	4.4%	5.2%	6.5%	6.7%	7.2%	8.0%	7.8%	5.3%	6.8%	6.9%	6.5%	6.1%	6.2%	5.8%	5.1%	4.7%	3.4%	5.4%	3.7%	2.7%	1.7%	-0.1%	2.0%	0.27%
Amesbury Newburyport	105.1%	1.3%	1.6%	2.2%	2.2%	3.0%	3.5%	4.0%	4.3%	5.2%	5.5%	5.9%	6.3%	7.2%	7.2%	5.2%	5.7%	8.0%	6.2%	4.5%	3.4%	3.0%	1.6%	4.3%	3.1%	2.3%	1.4%	0.0%	2.1%	0.33%
Attleboro	103.2%	0.9%	0.9%	1.6%	1.7%	2.9%	3.9%	4.1%	4.6%	6.8%	8.1%	8.3%	6.6%	7.5%	7.5%	7.6%	5.5%	7.6%	6.1%	5.1%	4.2%	3.0%	1.2%	3.5%	1.9%	1.5%	0.9%	-0.1%	2.1%	0.33%
Ayer Clinton	102.7%	2.6%	2.7%	2.6%	2.2%	3.0%	3.1%	3.7%	4.1%	4.5%	4.7%	5.8%	5.5%	5.7%	5.0%	5.2%	5.2%	5.5%	5.7%	4.4%	3.5%	2.9%	1.9%	2.1%	1.9%	1.2%	0.7%	0.7%	1.4%	0.27%
Barre-Athol	102.7%	4.0%	3.5%	3.5%	3.7%	4.4%	5.6%	6.5%	7.3%	7.3%	8.1%	10.2%	8.4%	5.8%	7.0%	6.2%	5.7%	3.1%	3.8%	2.5%	1.9%	1.7%	1.7%	1.5%	1.5%	1.2%	0.7%	1.0%	1.0%	0.27%
Beverly	105.1%	1.6%	1.7%	2.2%	2.1%	3.1%	2.9%	3.4%	3.5%	4.1%	5.6%	6.2%	6.1%	6.0%	7.9%	5.7%	7.6%	7.0%	6.2%	5.1%	4.4%	3.8%	1.4%	3.2%	2.1%	1.4%	0.8%	-0.3%	2.2%	0.33%
Billerica	102.7%	1.4%	1.4%	2.0%	2.0%	2.9%	3.5%	3.9%	4.6%	5.1%	5.2%	5.6%	7.5%	6.2%	6.5%	6.6%	4.6%	8.1%	6.0%	4.5%	3.5%	3.0%	1.3%	4.0%	2.4%	1.9%	1.2%	-0.2%	2.3%	0.27%
Bridgewater	103.2%	0.6%	1.2%	1.7%	2.3%	3.2%	3.9%	4.8%	5.4%	6.8%	7.9%	8.8%	8.5%	8.2%	8.8%	7.1%	4.9%	7.4%	6.7%	4.4%	3.9%	2.9%	1.6%	3.6%	2.3%	1.7%	1.1%	-0.1%	2.0%	0.33%
Brockton	103.2%	0.5%	0.8%	1.3%	1.2%	2.1%	3.0%	3.1%	3.8%	4.6%	5.4%	6.0%	6.8%	6.0%	7.1%	5.8%	5.4%	6.8%	5.7%	4.3%	3.8%	3.0%	2.0%	3.8%	2.5%	2.0%	1.3%	0.4%	1.8%	0.33%
Brockton NW / Randolph	103.2%	0.7%	1.0%	1.6%	1.5%	2.4%	3.2%	3.6%	3.9%	4.8%	6.4%	7.1%	7.1%	6.7%	7.6%	7.0%	5.2%	7.3%	6.6%	5.4%	4.6%	4.1%	2.3%	4.0%	2.3%	1.9%	1.4%	-0.1%	2.1%	0.33%
Cape Ann	105.1%	1.7%	2.1%	2.4%	2.2%	3.5%	3.2%	4.7%	4.7%	5.6%	6.9%	7.2%	5.6%	7.6%	8.0%	7.1%	6.2%	8.8%	5.8%	4.5%	3.7%	2.7%	0.4%	3.0%	1.6%	1.3%	0.7%	-0.3%	2.1%	0.33%
Chelmsford Westford	102.7%	1.3%	1.7%	2.1%	2.1%	2.8%	3.2%	3.4%	3.8%	4.5%	4.9%	4.6%	6.6%	6.6%	7.1%	6.0%	6.0%	6.6%	5.6%	4.1%	4.2%	3.6%	1.9%	4.8%	3.2%	2.9%	2.1%	0.7%	2.5%	0.27%
Dracut	104.0%	1.3%	1.5%	2.3%	2.3%	3.2%	4.0%	4.6%	5.3%	5.9%	6.1%	6.4%	9.4%	7.8%	8.2%	8.0%	5.5%	8.6%	6.7%	5.0%	4.1%	3.8%	2.2%	4.3%	2.5%	1.9%	1.3%	0.1%	2.0%	0.31%
Everett Malden Medford	105.1%	1.3%	1.6%	2.1%	1.9%	2.6%	3.0%	3.3%	3.5%	4.3%	4.4%	4.6%	6.4%	6.5%	6.4%	6.1%	7.9%	7.2%	7.9%	6.2%	5.4%	5.0%	3.4%	6.1%	4.2%	3.4%	2.3%	0.8%	2.1%	0.33%
Fall River	103.2%	0.5%	0.5%	1.0%	0.7%	1.5%	2.6%	2.8%	3.3%	3.6%	3.6%	4.1%	7.7%	5.4%	6.4%	6.0%	6.2%	5.8%	6.0%	5.1%	4.4%	4.0%	4.1%	2.7%	2.9%	2.2%	1.4%	2.0%	0.5%	0.33%
Gardner Winchendon	102.7%	2.3%	2.0%	2.3%	2.5%	2.8%	3.6%	3.9%	4.1%	5.1%	6.1%	7.1%	6.0%	5.5%	6.1%	4.6%	6.9%	4.5%	5.3%	3.4%	2.0%	2.0%	2.1%	1.1%	1.5%	1.2%	0.7%	1.4%	0.6%	0.27%
Hanover	103.2%	0.6%	1.3%	2.3%	2.3%	3.1%	4.0%	4.2%	4.4%	6.8%	8.7%	8.4%	7.2%	9.0%	8.0%	6.7%	4.7%	8.2%	6.9%	4.7%	4.1%	3.5%	1.7%	3.9%	2.9%	2.3%	1.6%	0.2%	1.9%	0.33%
Haverhill	105.1%	1.1%	1.3%	1.6%	1.5%	2.2%	3.1%	3.5%	3.7%	4.1%	4.7%	5.4%	8.3%	5.9%	6.5%	6.2%	5.7%	6.0%	6.9%	5.1%	6.0%	5.1%	3.7%	6.1%	4.0%	3.2%	2.2%	0.9%	2.4%	0.33%
Hopedale East	103.2%	1.4%	1.6%	2.2%	1.4%	2.6%	2.0%	2.8%	3.4%	4.4%	4.9%	5.2%	5.7%	6.1%	5.2%	5.5%	6.0%	5.5%	5.3%	4.1%	3.0%	2.6%	1.9%	3.1%	2.0%	1.6%	1.0%	0.4%	1.7%	0.33%
Hopedale West	103.2%	2.5%	3.1%	3.6%	3.7%	5.4%	3.0%	4.0%	4.3%	5.9%	7.2%	7.5%	6.4%	7.1%	6.8%	6.0%	6.4%	5.6%	6.3%	3.6%	2.7%	2.2%	0.7%	3.4%	1.5%	1.2%	0.7%	-0.4%	2.3%	0.33%
Lawrence	104.0%	1.1%	1.2%	1.4%	1.0%	1.6%	2.4%	2.2%	2.2%	2.7%	2.5%	2.8%	4.7%	3.9%	5.3%	-0.3%	9.5%	-3.6%	7.0%	3.5%	3.0%	10.3%	0.3%	2.3%	5.1%	1.9%	0.7%	4.1%	0.2%	0.31%
Leominster	102.7%	1.9%	2.0%	2.4%	2.0%	2.8%	3.1%	3.4%	3.8%	4.4%	4.7%	5.4%	5.5%	5.1%	5.2%	4.8%	5.4%	4.9%	5.1%	5.8%	4.8%	3.4%	2.9%	2.3%	2.2%	1.6%	1.1%	1.0%	1.5%	0.27%
Lowell	102.7%	1.1%	1.1%	1.2%	1.1%	1.7%	2.3%	2.2%	2.3%	2.6%	2.7%	3.5%	4.7%	3.8%	7.0%	4.7%	4.9%	5.1%	5.2%	4.5%	6.3%	5.0%	5.9%	4.8%	4.5%	3.4%	2.3%	1.0%	3.2%	0.27%
Lynn	105.1%	1.2%	1.4%	1.4%	1.4%	2.0%	2.2%	2.3%	2.5%	2.7%	3.0%	3.5%	4.1%	3.6%	4.7%	4.1%	4.7%	4.4%	4.7%	4.2%	3.8%	3.6%	4.0%	2.9%	2.6%	1.6%	1.0%	1.8%	0.6%	0.33%
Marlboro	102.7%	1.6%	2.0%	2.3%	2.6%	3.8%	1.8%	2.5%	2.8%	3.7%	4.1%	4.4%	5.1%	5.3%	5.8%	4.6%	5.0%	4.9%	5.3%	3.9%	3.2%	2.5%	2.6%	1.7%	1.7%	1.3%	0.8%	0.9%	1.2%	0.27%
Melrose Saugus	105.1%	1.4%	1.8%	2.2%	2.2%	3.0%	3.3%	3.7%	4.0%	4.7%	5.4%	6.1%	7.2%	6.9%	7.7%	6.6%	7.0%	7.7%	7.4%	5.4%	4.7%	4.6%	2.6%	4.9%	3.5%	2.7%	1.9%	0.3%	2.1%	0.33%
Methuen	104.0%	1.3%	1.4%	1.8%	1.8%	2.6%	3.5%	3.9%	4.5%	4.9%	5.2%	5.8%	8.3%	7.1%	6.9%	6.9%	6.2%	7.4%	6.6%	7.0%	5.8%	4.6%	2.4%	4.7%	3.3%	2.6%	1.9%	0.7%	2.2%	0.31%
Millbury-Grafton	102.7%	2.3%	2.6%	3.5%	3.3%	4.0%	3.6%	4.6%	4.5%	5.8%	6.9%	7.2%	6.2%	6.7%	7.8%	6.4%	6.7%	7.1%	6.0%	3.8%	2.7%	2.4%	1.4%	2.7%	1.8%	1.5%	1.0%	0.3%	1.9%	0.27%
Monson-Palmer-Longmeadow	102.7%	2.4%	2.3%	2.7%	2.8%	3.6%	4.3%	4.8%	4.9%	5.8%	6.7%	8.0%	6.2%	5.2%	7.2%	6.4%	5.8%	5.3%	4.7%	2.8%	2.2%	1.9%	1.5%	2.3%	1.7%	1.4%	0.8%	0.6%	1.4%	0.27%
Nantucket	114.0%	2.4%	2.2%	2.1%	2.5%	2.8%	3.0%	3.1%	3.1%	3.6%	3.9%	4.1%	4.4%	4.4%	4.4%	4.3%	4.2%	4.1%	4.0%	3.2%	2.9%	2.6%	2.3%	2.0%	1.7%	1.4%	1.2%	0.9%	0.7%	1.75%
North Andover	104.0%	1.4%	1.6%	1.9%	1.8%	2.6%	2.5%	3.0%	3.5%	4.1%	4.2%	4.6%	6.1%	5.9%	5.5%	4.7%	5.0%	5.4%	5.0%	4.0%	3.5%	3.2%	2.2%	2.9%	2.5%	1.9%	1.1%	0.9%	1.4%	0.31%
North Lowell	102.7%	1.5%	1.4%	2.0%	1.8%	2.7%	3.3%	3.6%	4.1%	4.7%	4.9%	5.2%	7.9%	6.4%	7.7%	7.4%	6.2%	7.9%	7.5%	6.2%	5.4%	5.1%	2.8%	5.1%	3.5%	3.2%	1.7%	0.6%	2.6%	0.27%
Northampton-S berkshire	102.7%	2.1%	2.3%	2.6%	2.5%	3.3%	4.0%	4.3%	5.2%	5.4%	6.2%	7.8%	7.6%	5.8%	7.5%	5.9%	8.5%	7.1%	6.7%	4.6%	3.7%	3.5%	1.6%	4.1%	2.0%	1.5%	1.0%	-0.2%	2.3%	0.27%
Pepperell Dunstable	102.7%	1.6%	2.4%	3.1%	3.6%	5.1%	4.4%	5.7%	5.9%	6.4%	7.3%	7.0%	6.3%	11.3%	8.1%	7.6%	5.1%	8.2%	4.8%	3.5%	3.2%	2.9%	1.2%	4.4%	3.1%	1.7%	0.8%	-0.2%	1.9%	0.27%
Quincy	103.2%	0.3%	0.6%	1.4%	1.1%	1.8%	2.6%	2.6%	2.9%	3.8%	4.5%	5.1%	6.8%	6.4%	6.8%	6.4%	7.0%	10.2%	9.2%	7.7%	6.9%	6.3%	4.1%	5.8%	2.9%	1.9%	1.2%	0.0%	2.1%	0.33%
Revere Winthrop	105.1%	1.2%	1.6%	2.0%	1.9%	2.9%	3.4%	4.0%	4.1%	4.7%	4.3%	4.6%	6.8%	5.4%	6.2%	6.7%	7.0%	7.5%	7.0%	6.7%	6.0%	7.1%	5.3%	7.8%	5.7%	3.7%	2.6%	1.4%	2.6%	0.33%
Salem Swampscott	105.1%	1.4%	1.8%	2.2%	2.1%	2.9%	3.1%	3.4%	3.7%	4.6%	5.4%	6.2%	7.9%	6.5%	7.0%	6.9%	6.9%	8.5%	7.6%	6.4%	5.6%	5.3%	3.9%	5.0%	2.8%	1.9%	1.0%	-0.1%	2.0%	0.33%
Scituate	103.2%	0.5%	1.8%	3.4%	3.4%	4.0%	5.5%	5.1%	5.3%	7.4%	7.6%	5.7%	6.1%	13.3%	7.4%	4.8%	3.2%	6.4%	5.1%	3.6%	3.3%	3.1%	1.6%	4.2%	2.9%	2.2%	1.4%	-0.8%	2.8%	0.33%
Somerset	103.2%	0.6%	0.9%	1.6%	2.0%	3.8%	4.9%	5.7%	5.8%	7.2%	8.2%	8.8%	7.4%	7.4%	10.0%	6.2%	3.6%	6.7%	5.4%	3.8%	3.5%	3.1%	1.7%	4.0%	2.7%	1.9%	1.2%	0.0%	2.0%	0.33%
Spencer-Rutland	102.7%	1.7%	1.8%	1.9%	2.5%	2.8%	3.3%	3.9%	4.1%	5.8%	6.0%	6.7%	3.9%	6.4%	6.7%	6.5%	4.0%	7.0%	4.9%	2.6%	1.8%	1.6%	-0.1%	3.1%	1.4%	1.1%	0.7%	-0.6%	2.5%	0.27%
Tewksbury	104.0%	1.3%	1.6%	1.9%	1.8%	2.6%	3.0%	3.4%	3.8%	4.3%	4.9%	5.2%	5.9%	6.5%	5.8%	4.5%	4.1%	5.7%	5.1%	4.1%	3.4%	3.2%	1.4%	3.5%	2.3%	1.8%	1.2%	0.5%	1.9%	0.31%
Topsfield	105.1%	1.6%	3.0%	4.2%	5.3%	5.9%	5.6%	6.2%	5.7%	6.2%	4.8%	4.7%	4.3%	11.8%	8.7%	5.1%	3.7%	7.3%	4.8%	3.4%	3.1%	2.8%	1.7%	3.1%	1.5%	1.2%	0.8%	-0.4%	2.3%	0.33%
Webster Southbridge Charlton	102.7%	2.4%	2.4%	2.6%	2.5%	3.4%	3.3%	3.8%	4.1%	5.1%	5.9%	6.8%	6.2%	5.6%	6.3%	5.0%	6.6%	4.4%	4.8%	3.4%	2.8%	2.3%	2.2%	2.1%	1.8%	1.3%	0.8%	-0.4%	2.6%	0.27%
Weymouth Holbrook	103.2%	0.7%	1.3%	1.9%	1.7%	2.5%	3.3%	3.6%	4.2%	5.4%	7.4%	7.7%	7.6%	8.5%	8.6%	7.6%	5.2%	9.6%	8.2%	6.1%	5.4%	4.8%	2.5%	3.3%	2.0%	1.4%	0.8%	-0.1%	2.0%	0.33%
Worcester North	102.7%	1.7%	2.0%	2.4%	2.1%	2.6%	3.1%	3.1%	3.2%	3.5%	3.9%	4.9%	5.5%	4.4%	5.5%	4.7%	4.5%	5.6%	5.6%	3.9%	4.0%	3.7%	3.9%	2.9%	2.4%	1.9%	1.1%	1.3%	1.2%	0.27%
Worcester South	102.7%	1.8%	1.9%	2.3%	1.9%	2.4%	2.8%	2.8%	3.0%	3.3%	3.4%	3.9%	4.7%	4.7%	4.8%	4.4%	4.7%	4.7%	4.9%	4.2%	4.0%	3.7%	4.0%	3.3%	3.0%	2.0%	1.2%	1.8%	1.2%	0.27%

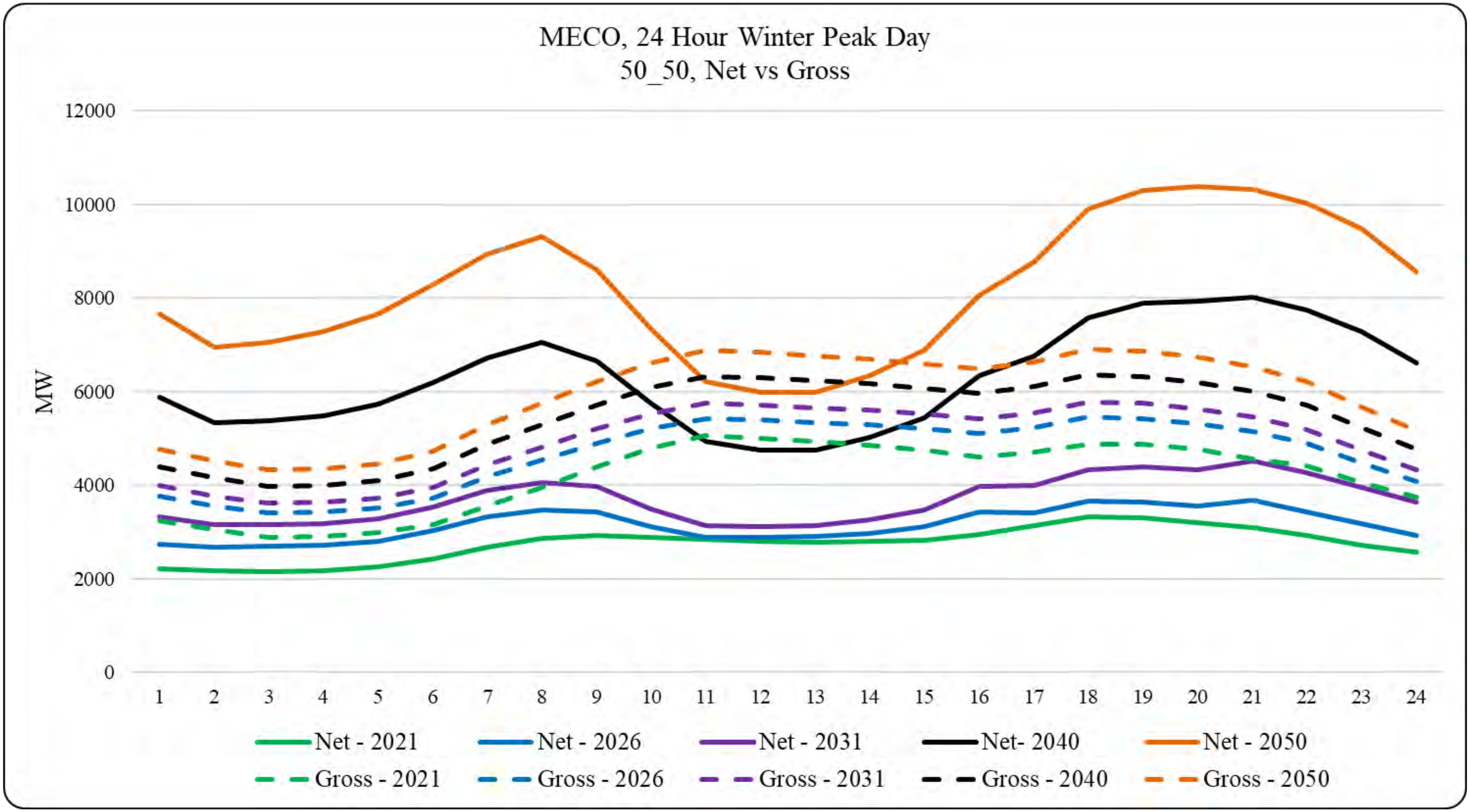
Appendix D: Historical Summer Peaks Days and Hours

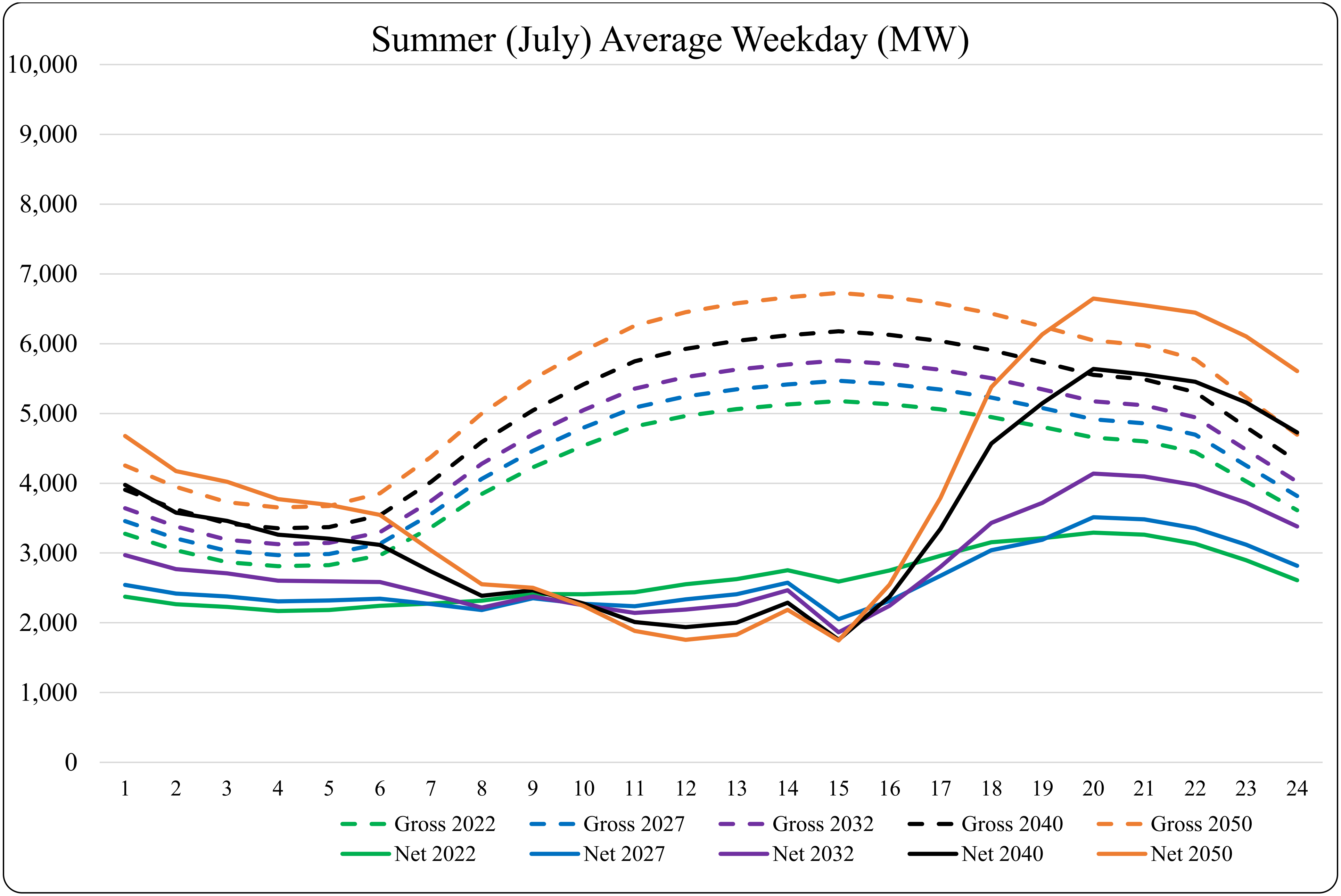
year	dt_wcma	hr_wcma	dt_nema	hr_nema	dt_sema	hr_sema	dt_ma	hr_ma	dt_nant	hr_nant	dt_meco	hr_meco
2003	6/27/2003	14	8/22/2003	16	8/22/2003	15	8/22/2003	15	8/8/2003	19	6/27/2003	14
2004	8/30/2004	16	8/3/2004	17	8/30/2004	16	8/30/2004	16	8/20/2004	20	8/30/2004	16
2005	7/27/2005	15	7/27/2005	17	7/27/2005	16	7/27/2005	16	8/5/2005	19	7/27/2005	16
2006	8/2/2006	15	8/2/2006	17	8/2/2006	16	8/2/2006	16	8/3/2006	19	8/2/2006	16
2007	6/27/2007	15	6/27/2007	16	8/3/2007	15	6/27/2007	15	8/3/2007	19	6/27/2007	15
2008	6/10/2008	17	6/10/2008	18	6/10/2008	17	6/10/2008	17	8/2/2008	19	6/10/2008	17
2009	8/18/2009	14	8/18/2009	14	8/18/2009	15	8/18/2009	14	8/21/2009	19	8/18/2009	14
2010	7/7/2010	15	7/6/2010	15	7/6/2010	17	7/6/2010	15	8/6/2010	18	7/6/2010	15
2011	7/22/2011	14	7/22/2011	15	7/22/2011	16	7/22/2011	15	7/22/2011	19	7/22/2011	15
2012	7/17/2012	17	7/17/2012	18	7/17/2012	16	7/17/2012	17	8/4/2012	19	7/17/2012	17
2013	7/19/2013	15	7/19/2013	17	7/19/2013	15	7/19/2013	15	7/19/2013	18	7/19/2013	15
2014	7/2/2014	15	7/2/2014	16	9/2/2014	16	7/2/2014	16	7/3/2014	19	7/2/2014	16
2015	9/8/2015	17	9/9/2015	17	7/20/2015	18	7/20/2015	17	7/29/2015	18	7/20/2015	17
2016	8/12/2016	15	8/12/2016	16	8/12/2016	16	8/12/2016	15	8/14/2016	18	8/12/2016	15
2017	6/13/2017	17	6/13/2017	17	6/13/2017	18	6/13/2017	17	7/20/2017	19	6/13/2017	17
2018	8/29/2018	18	8/29/2018	18	8/29/2018	18	8/29/2018	18	8/6/2018	18	8/29/2018	18
2019	7/30/2019	19	7/30/2019	18	7/21/2019	18	7/30/2019	18	7/21/2019	18	7/30/2019	18
2020	7/27/2020	18	7/27/2020	18	7/27/2020	18	7/27/2020	18	7/28/2020	19	7/27/2020	18
2021	6/29/2021	18	6/30/2021	17	6/30/2021	18	6/29/2021	18	8/13/2021	18	6/29/2021	18
2022	8/4/2022	18	8/8/2022	18	8/9/2022	15	8/8/2022	18	8/6/2022	18	8/8/2022	18

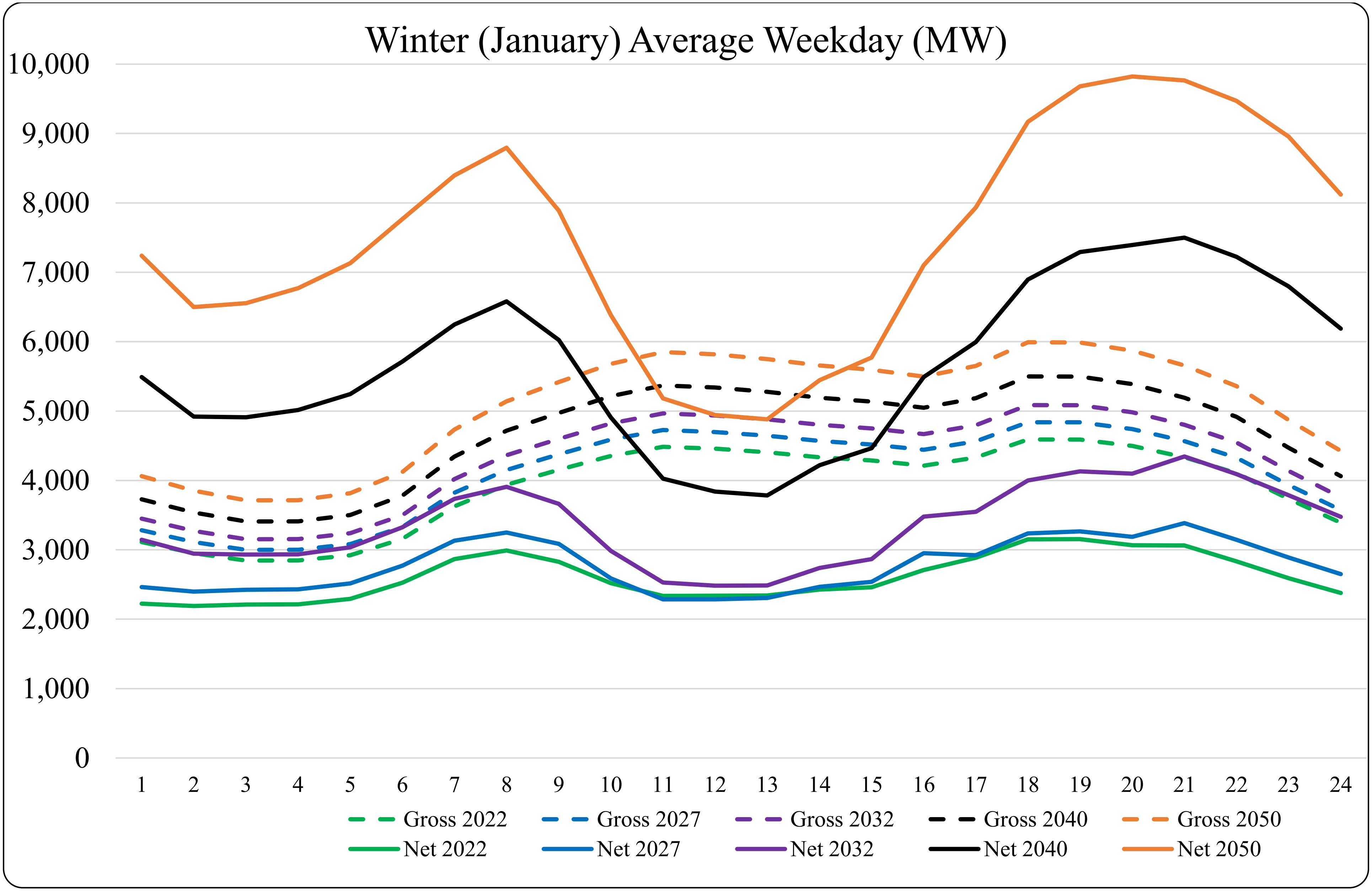
Appendix E: Load Shapes for Typical Day Types

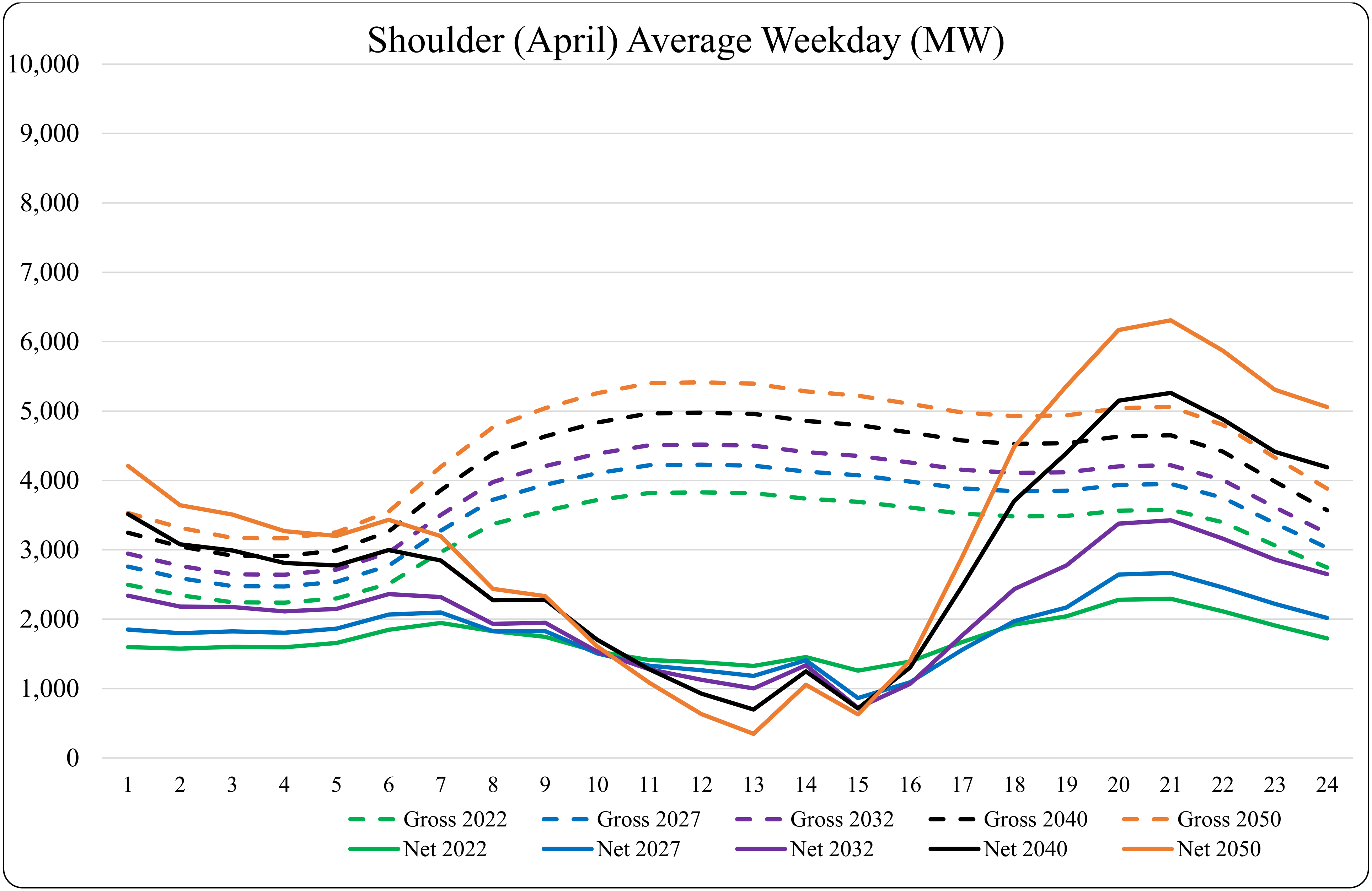
(for Base Case)


MECO, 24 Hour Summer Peak Day
50_50, Net vs Gross
MW
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Net - 2022
Gross - 2022
Net - 2027
Gross - 2027
Net - 2032
Gross - 2032
Net- 2040
Gross - 2040
Net - 2050
Gross - 2050

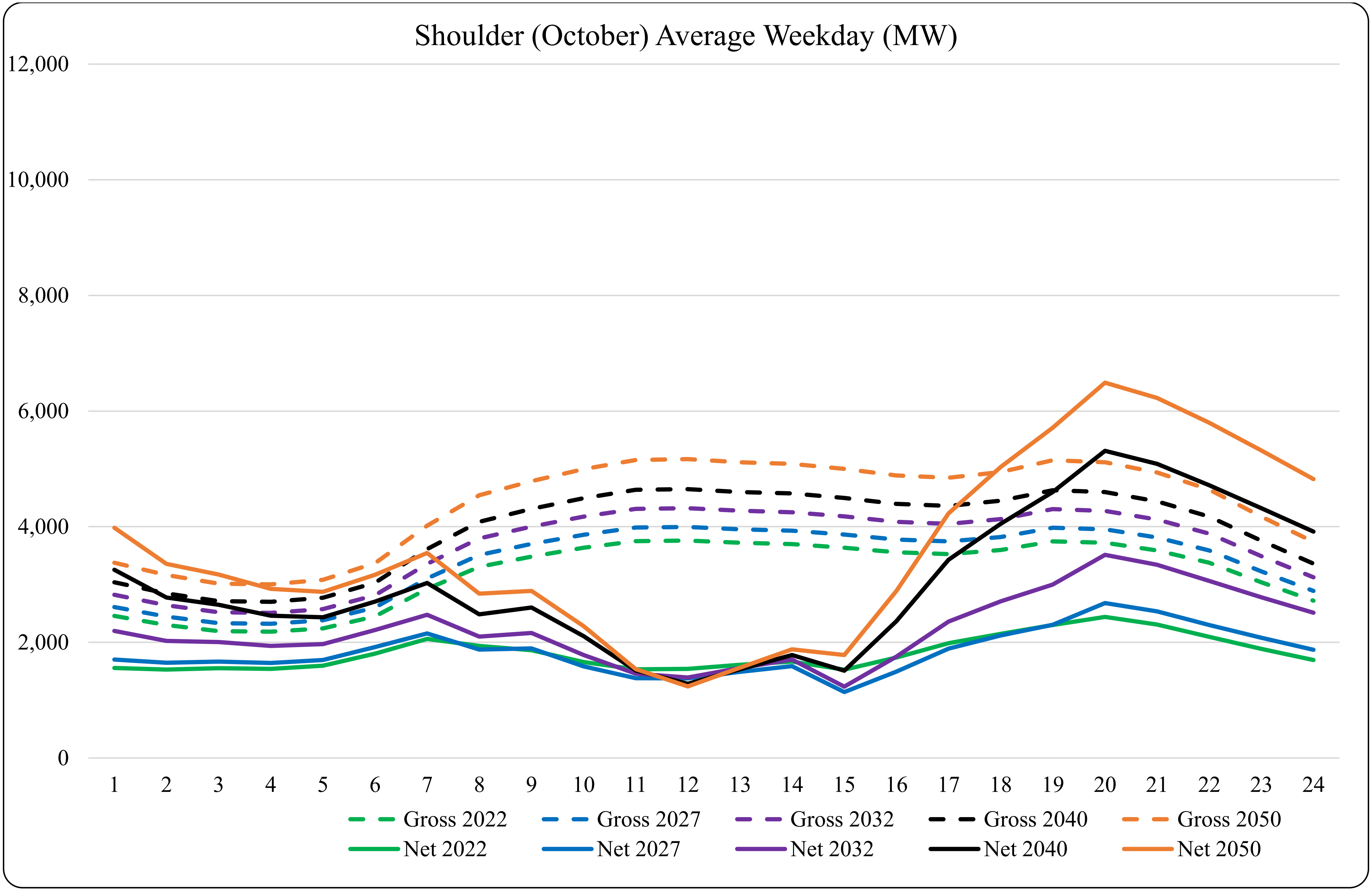

MECO, 24 Hour Winter Peak Day
50_50, Net vs Gross
MW
12000
10000
8000
6000
4000
2000
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Net - 2021
Net - 2026
Net - 2031
Net- 2040
Net - 2050
Gross - 2021
Gross - 2026
Gross - 2031
Gross - 2040
Gross - 2050


Summer (July) Average Weekday (MW)
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Gross 2022
Gross 2027
Gross 2032
Gross 2040
Gross 2050
Net 2022
Net 2027
Net 2032
Net 2040
Net 2050

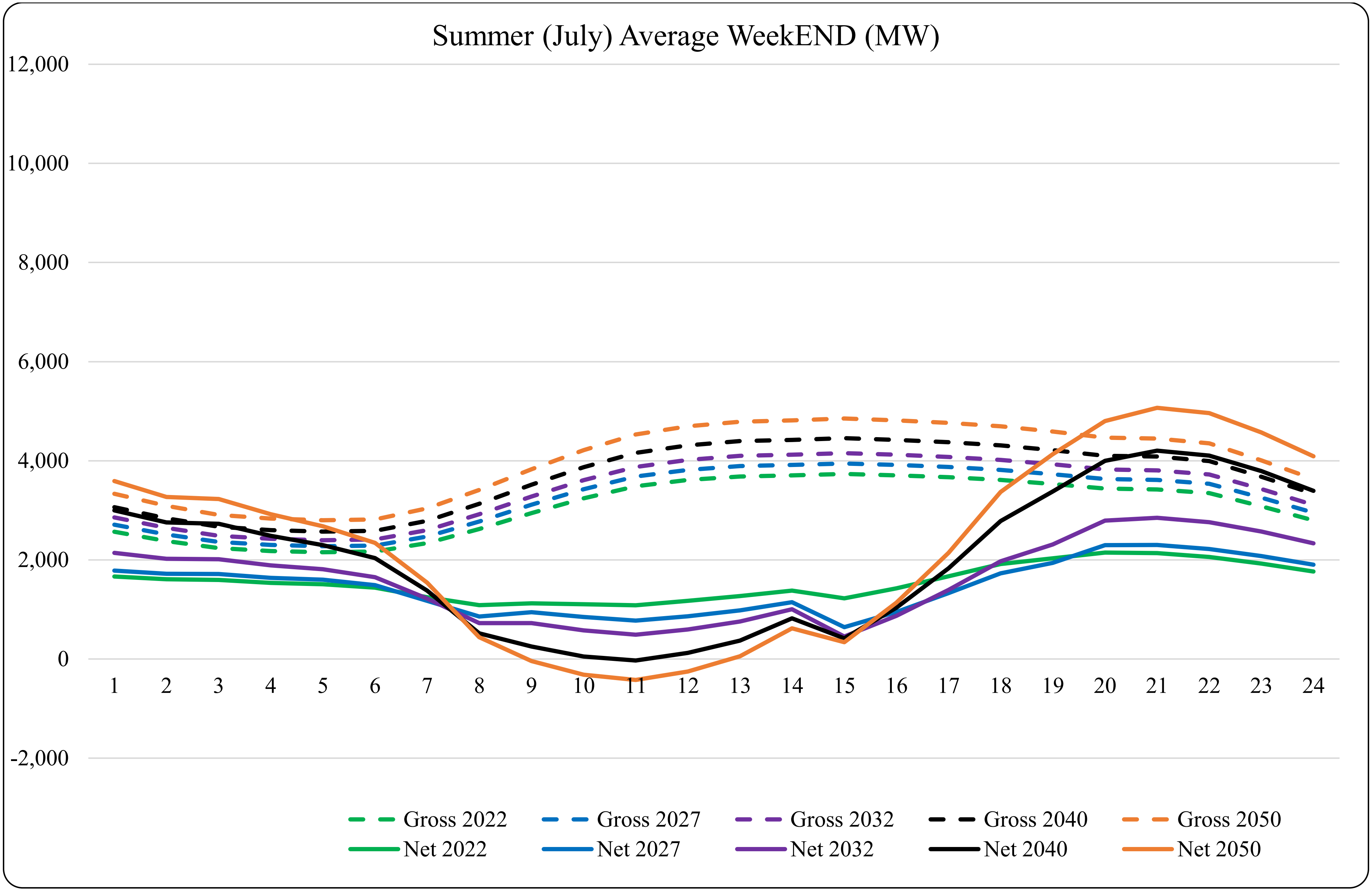

Winter (January) Average Weekday (MW)
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2022
Gross 2027
Gross 2032
Gross 2040
Gross 2050
Net 2022
Net 2027
Net 2032
Net 2040
Net 2050



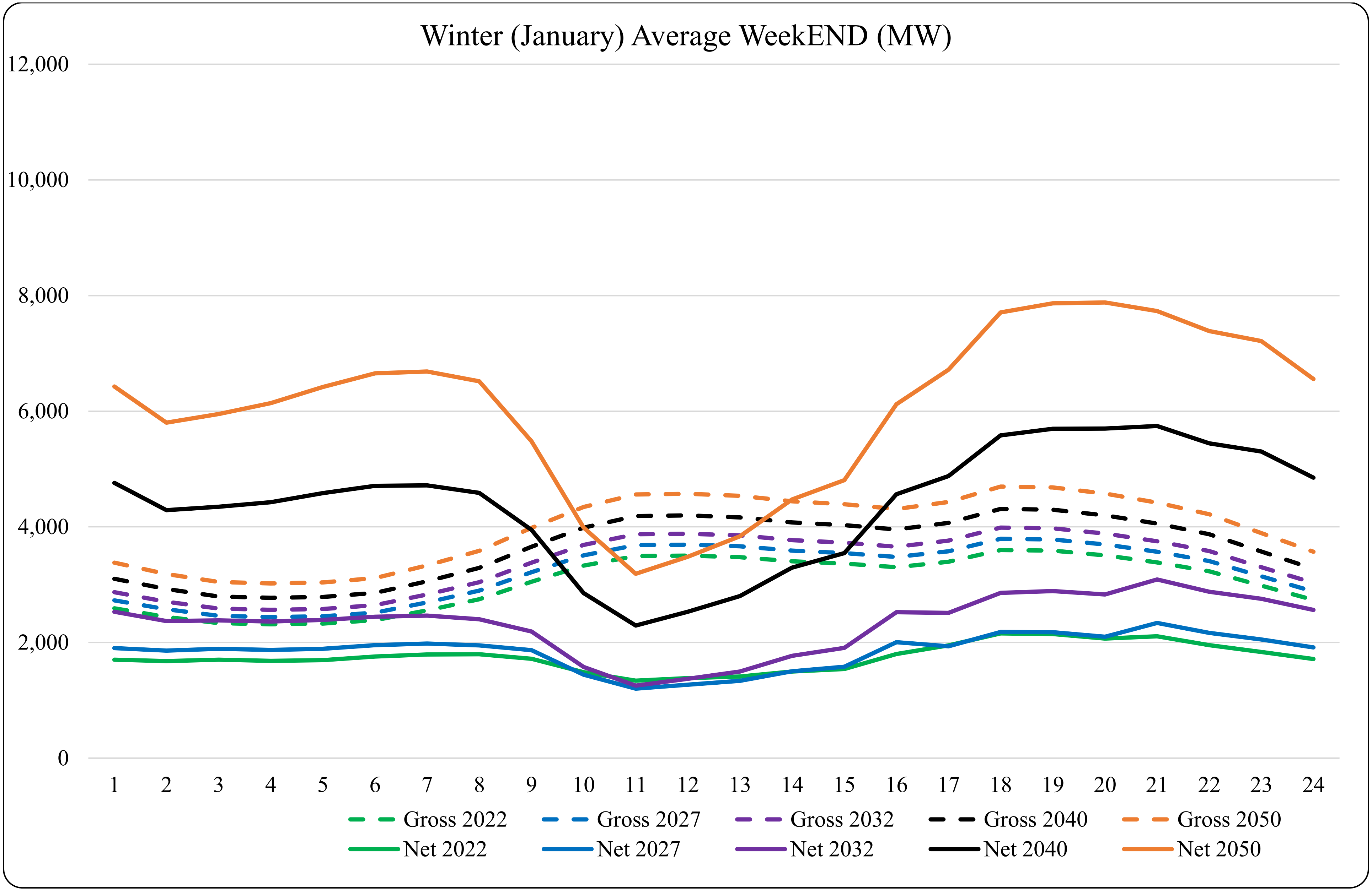
Shoulder (April) Average Weekday (MW)
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2022
Gross 2027
Gross 2032
Gross 2040
Gross 2050
Net 2022
Net 2027
Net 2032
Net 2040
Net 2050



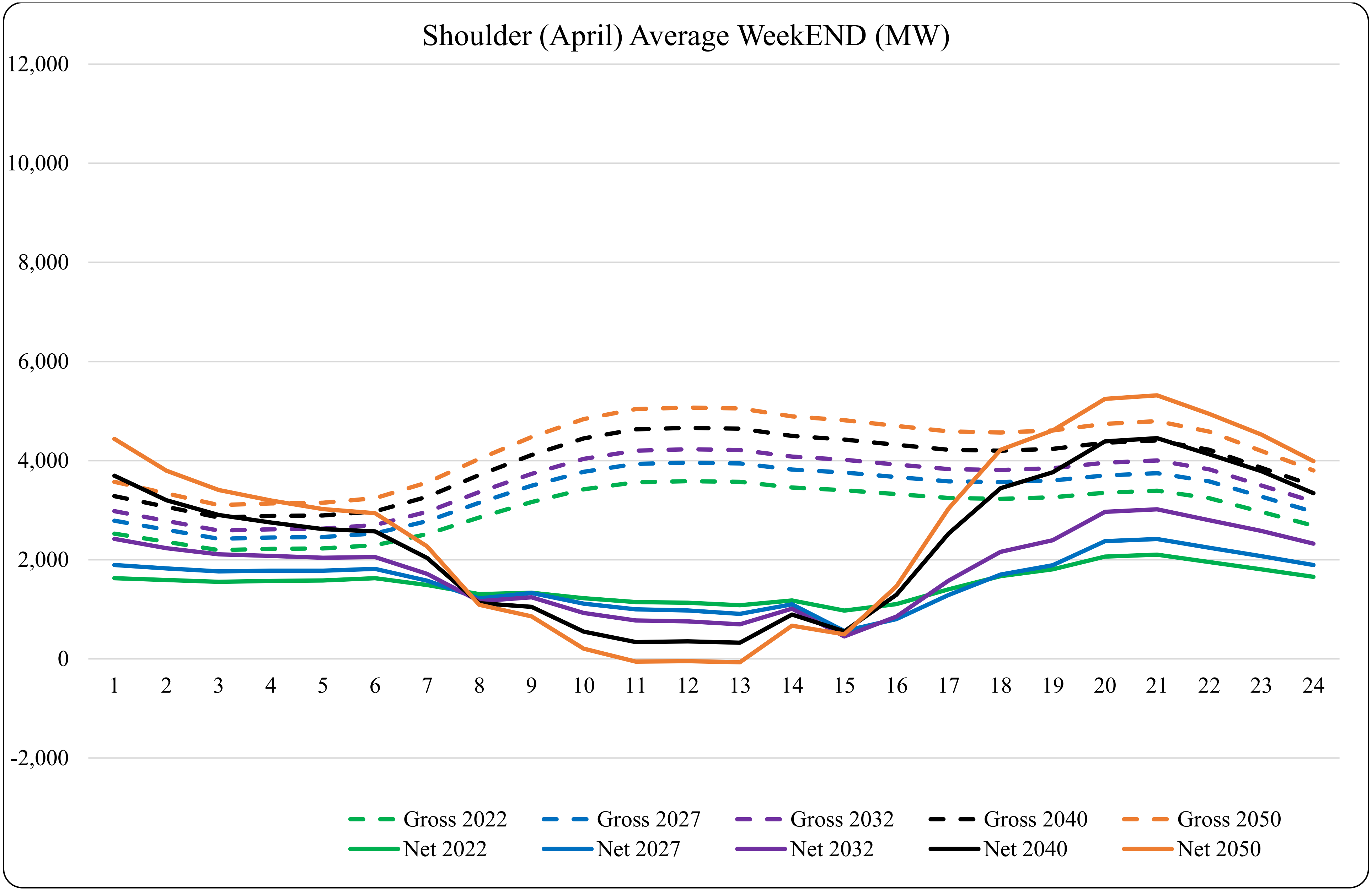
Shoulder (October) Average Weekday (MW)
12,000
10,000
8,000
6,000
4,000
2,000
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Gross 2022
Gross 2027
Gross 2032
Gross 2040
Gross 2050
Net 2022
Net 2027
Net 2032
Net 2040
Net 2050



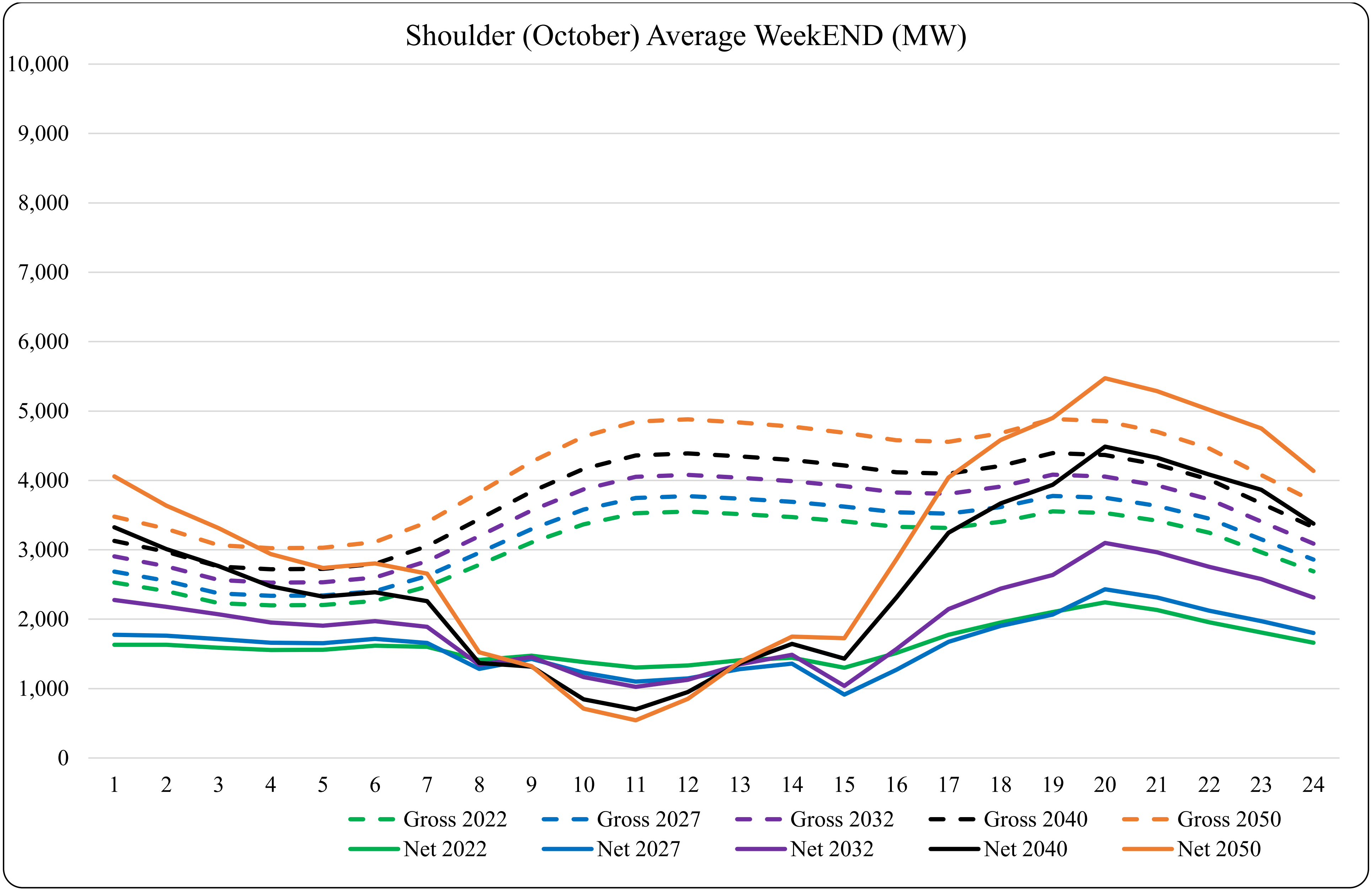
Summer (July) Average WeekEND (MW)
12,000
10,000
8,000
6,000
4,000
2,000
0
-2,000
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Gross 2022
Gross 2027
Gross 2032
Gross 2040
Gross 2050
Net 2022
Net 2027
Net 2032
Net 2040
Net 2050



Winter (January) Average WeekEND (MW)
12,000
10,000
8,000
6,000
4,000
2,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2022
Gross 2027
Gross 2032
Gross 2040
Gross 2050
Net 2022
Net 2027
Net 2032
Net 2040
Net 2050



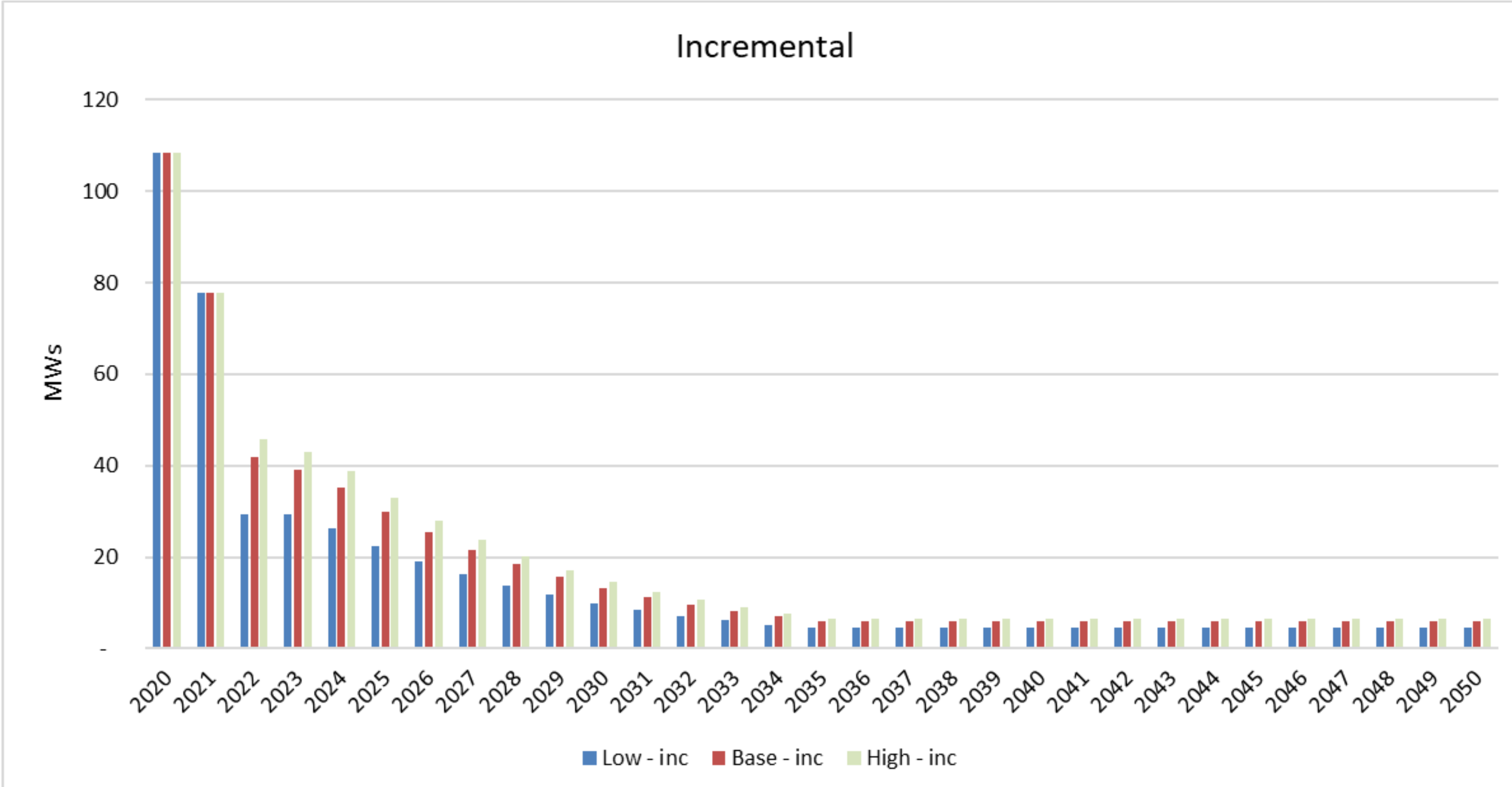
Shoulder (April) Average WeekEND (MW)
12,000
10,000
8,000
6,000
4,000
2,000
0
-2,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2022
Gross 2027
Gross 2032
Gross 2040
Gross 2050
Net 2022
Net 2027
Net 2032
Net 2040
Net 2050


Shoulder (October) Average WeekEND (MW)
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2022
Gross 2027
Gross 2032
Gross 2040
Gross 2050
Net 2022
Net 2027
Net 2032
Net 2040
Net 2050

Appendix F: DER Scenarios Inputs

Energy Efficiency

Summer Peak MWs						
Year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum
2020	108	1,196	108	1,196	108	1,196
2021	78	1,274	78	1,274	78	1,274
2022	29	1,303	42	1,316	46	1,320
2023	29	1,332	39	1,355	43	1,363
2024	26	1,359	35	1,390	39	1,401
2025	22	1,381	30	1,420	33	1,434
2026	19	1,400	25	1,445	28	1,462
2027	16	1,416	22	1,467	24	1,486
2028	14	1,430	18	1,485	20	1,506
2029	12	1,442	16	1,501	17	1,523
2030	10	1,452	13	1,514	15	1,538
2031	8	1,460	11	1,525	12	1,550
2032	7	1,468	10	1,535	11	1,561
2033	6	1,474	8	1,543	9	1,570
2034	5	1,479	7	1,550	8	1,577
2035	4	1,483	6	1,556	6	1,584
2036	4	1,488	6	1,562	6	1,590
2037	4	1,492	6	1,568	6	1,597
2038	4	1,496	6	1,573	6	1,603
2039	4	1,501	6	1,579	6	1,610
2040	4	1,505	6	1,585	6	1,616
2041	4	1,510	6	1,591	6	1,623
2042	4	1,514	6	1,597	6	1,629
2043	4	1,519	6	1,603	6	1,636
2044	4	1,523	6	1,609	6	1,642
2045	4	1,527	6	1,615	6	1,649
2046	4	1,532	6	1,620	6	1,655
2047	4	1,536	6	1,626	6	1,662
2048	4	1,541	6	1,632	6	1,668
2049	4	1,545	6	1,638	6	1,674
2050	4	1,549	6	1,644	6	1,681


Incremental
MWs
120
100
80
60
40
20
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
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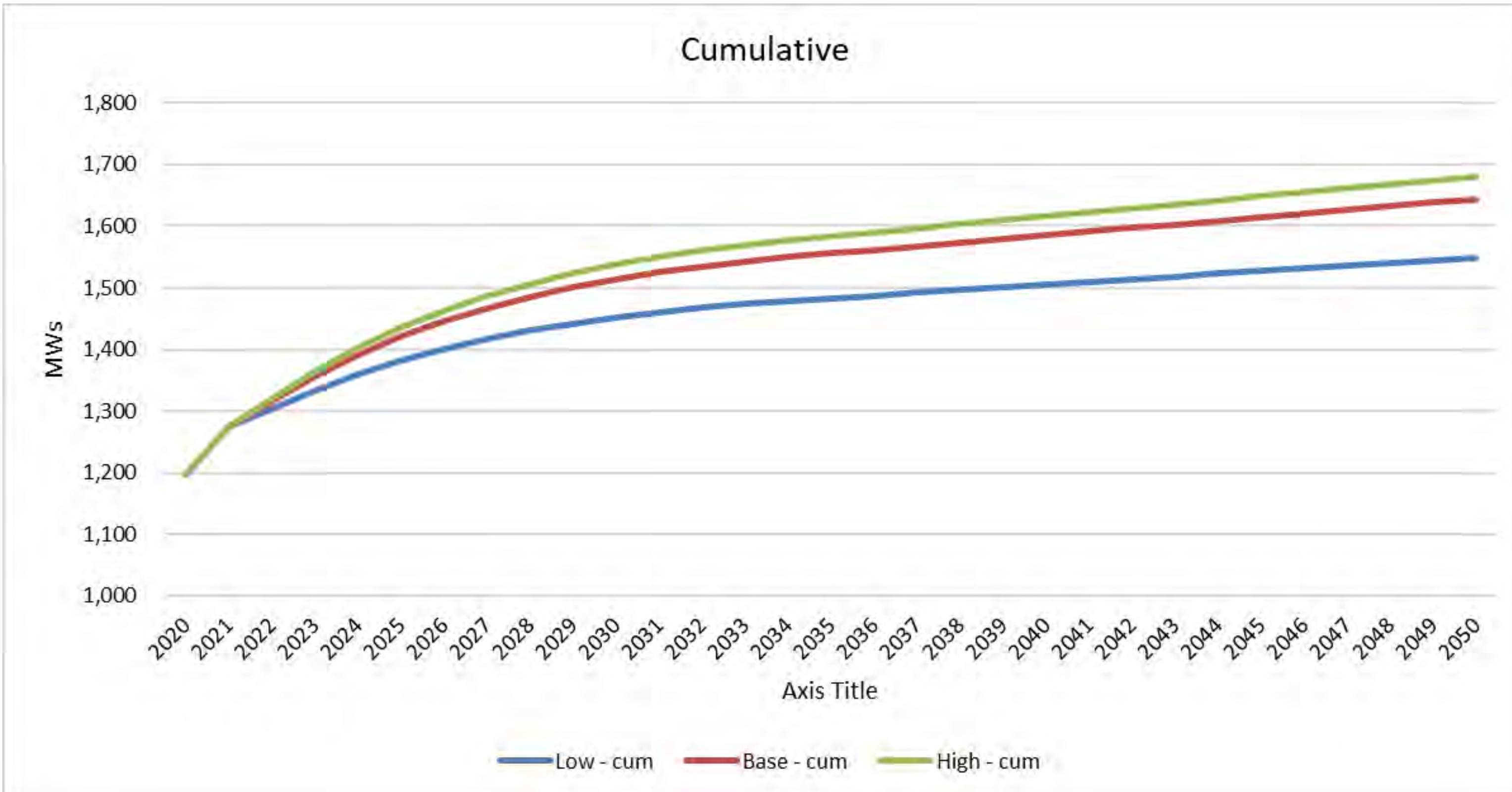
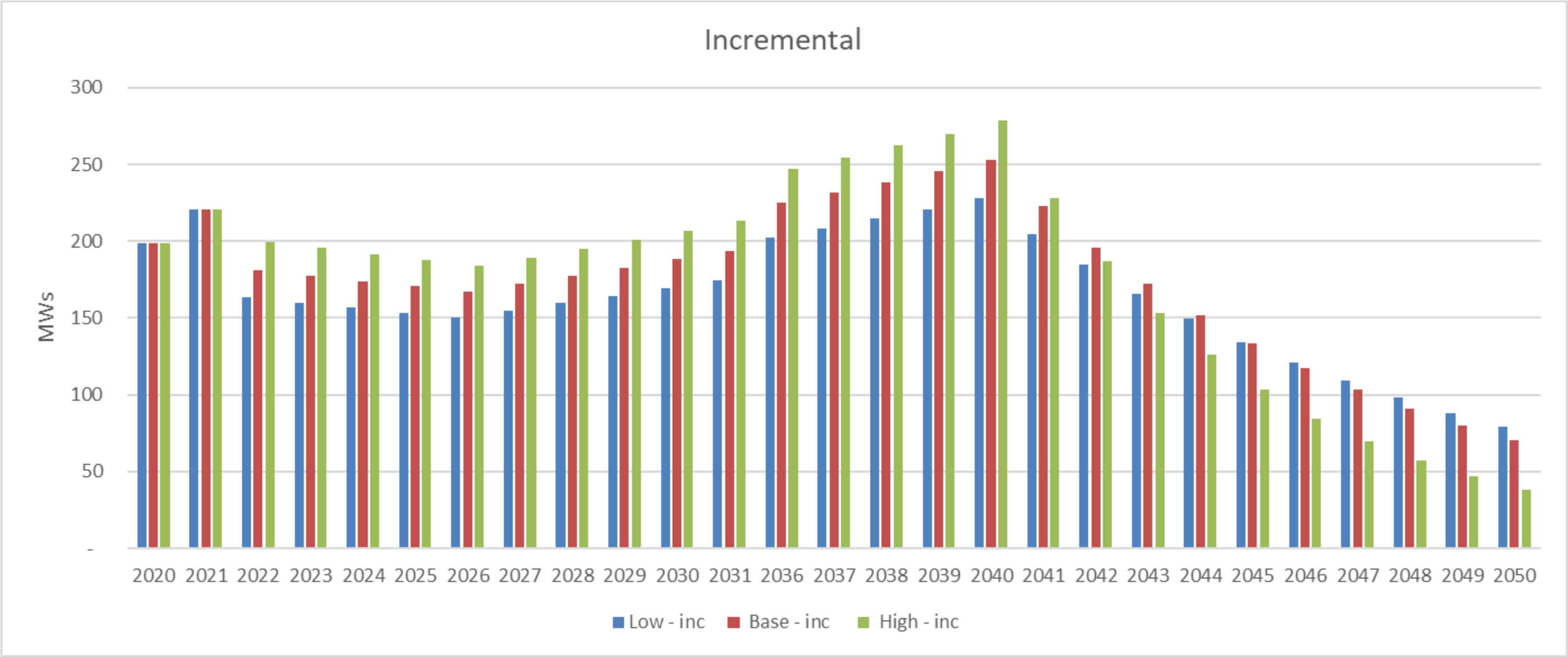
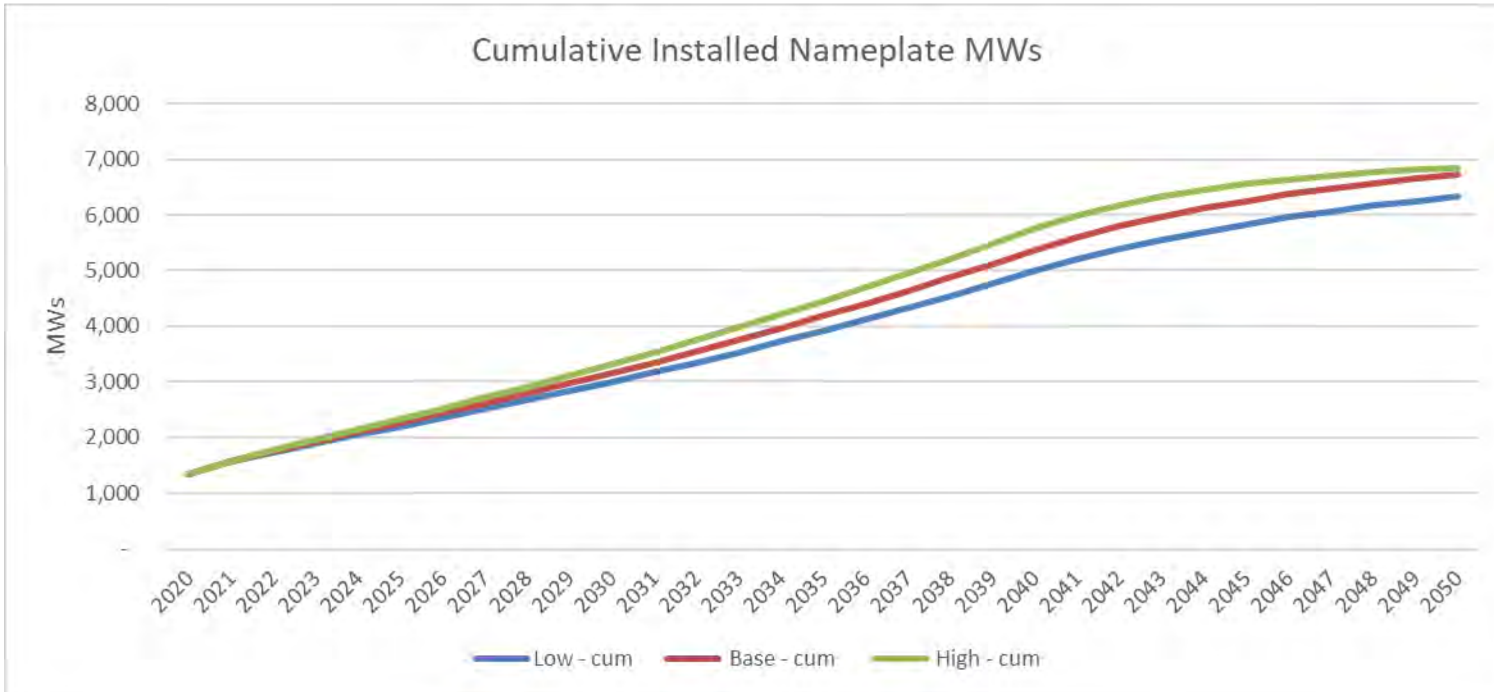
2046
2047
2048
2049
2050
Low - inc
Base - inc
High - inc


Cumulative
1,800
1,700
1,600
1,500
1,400
1,300
1,200
1,100
1,000
MWs
2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050
Axis Title
Low - cum
Base - cum
High - cum

Solar – PV

Connected Nameplated (MW)						
Year	**Low - inc**	**Low - cum**	**Base - inc**	**Base - cum**	**High - inc**	**High - cum**
2020	198	1,343	198	1,343	198	1,343
2021	221	1,564	221	1,564	221	1,564
2022	163	1,727	181	1,745	199	1,763
2023	160	1,887	178	1,923	195	1,959
2024	157	2,044	174	2,097	192	2,150
2025	154	2,197	171	2,268	188	2,338
2026	150	2,348	167	2,435	184	2,522
2027	155	2,503	172	2,607	189	2,711
2028	160	2,662	177	2,785	195	2,907
2029	164	2,827	183	2,967	201	3,108
2030	169	2,996	188	3,155	207	3,315
2031	174	3,171	194	3,349	213	3,528
2032	180	3,350	200	3,549	220	3,747
2033	185	3,536	206	3,755	226	3,974
2034	191	3,726	212	3,966	233	4,207
2035	196	3,923	218	4,185	240	4,447
2036	202	4,125	225	4,409	247	4,694
2037	208	4,333	231	4,641	255	4,948
2038	215	4,548	238	4,879	262	5,211
2039	221	4,769	246	5,125	270	5,481
2040	228	4,996	253	5,378	278	5,759
2041	205	5,201	223	5,600	228	5,987
2042	184	5,386	196	5,796	187	6,174
2043	166	5,552	172	5,969	153	6,328
2044	149	5,701	152	6,120	126	6,453
2045	134	5,835	133	6,254	103	6,557
2046	121	5,956	117	6,371	85	6,641
2047	109	6,065	103	6,474	69	6,711
2048	98	6,163	91	6,565	57	6,767
2049	88	6,251	80	6,645	47	6,814
2050	79	6,331	70	6,716	38	6,852


Incremental
300
250
200
150
100
50
-
MWs
2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050
Low - inc
Base - inc
High - inc



Cumulative Installed Nameplate MWs
MWs
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
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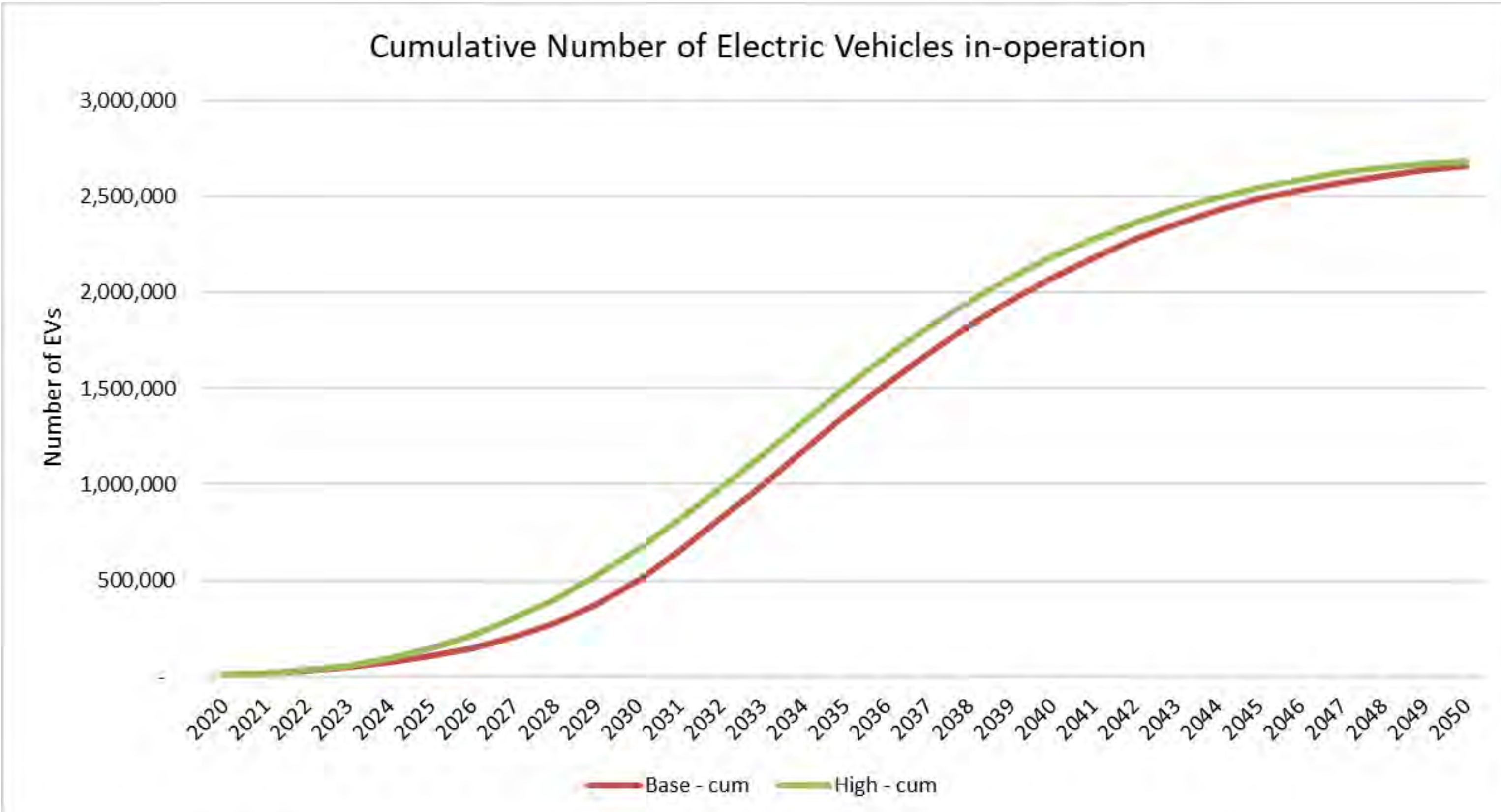
2040
2041
2042
2043
2044
2045
2046
2047
2048
2049
2050
Low - cum
Base - cum
High - cum

Electric Vehicles

Number of Vehicles				
Year	**Base - inc**	**Base - cum**	**High - inc**	**High - cum**
2020	2,847	13,919	2,847	13,919
2021	6,142	20,061	6,142	20,061
2022	12,167	32,228	14,070	34,131
2023	18,114	50,342	23,526	57,657
2024	24,477	74,819	36,733	94,390
2025	31,825	106,644	50,992	145,382
2026	42,982	149,626	70,386	215,768
2027	56,567	206,193	87,180	302,948
2028	72,673	278,866	103,774	406,722
2029	99,610	378,476	120,208	526,930
2030	122,001	500,477	138,469	665,399
2031	154,503	654,980	152,589	817,988
2032	164,701	819,681	162,128	980,116
2033	174,313	993,994	170,987	1,151,103
2034	181,691	1,175,685	177,535	1,328,638
2035	180,911	1,356,596	175,869	1,504,507
2036	168,802	1,525,398	162,786	1,667,293
2037	156,537	1,681,935	149,366	1,816,659
2038	142,846	1,824,781	134,543	1,951,202
2039	129,592	1,954,373	120,300	2,071,502
2040	120,268	2,074,641	110,266	2,181,768
2041	105,159	2,179,800	94,944	2,276,712
2042	93,758	2,273,558	83,547	2,360,259
2043	81,759	2,355,317	72,299	2,432,558
2044	70,212	2,425,529	61,593	2,494,151
2045	59,261	2,484,790	51,486	2,545,637
2046	49,290	2,534,080	41,567	2,587,204
2047	40,301	2,574,381	33,298	2,620,502
2048	32,761	2,607,142	26,407	2,646,909
2049	26,486	2,633,628	20,769	2,667,678
2050	21,402	2,655,030	16,259	2,683,937

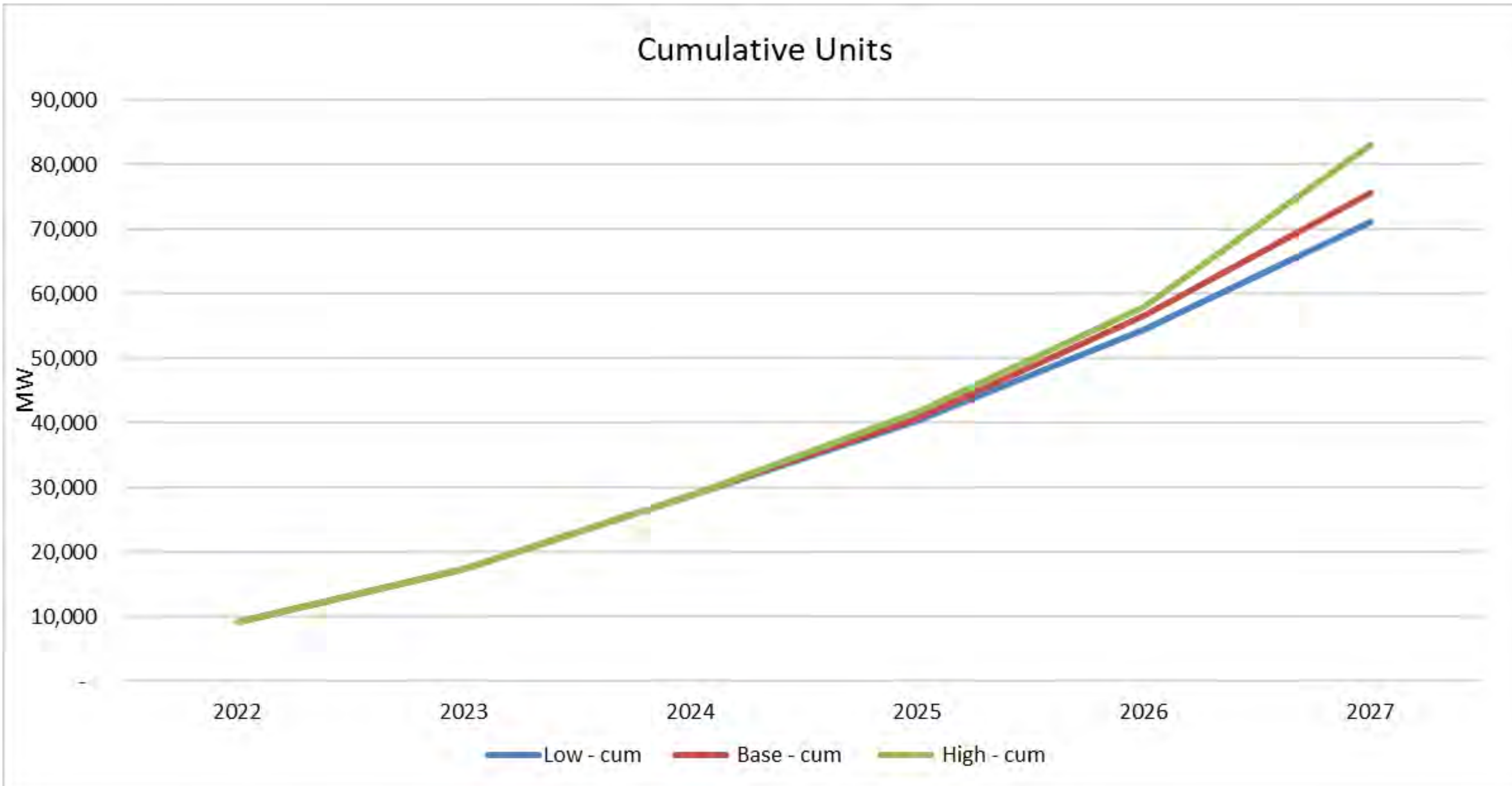
Number of Light-duty Vehicles				
Year	**Base - inc**	**Base - cum**	**High - inc**	**High - cum**
2020	2,840	13,912	2,840	13,912
2021	6,140	20,052	6,140	20,052
2022	12,165	32,217	14,068	34,120
2023	17,802	50,019	23,222	57,342
2024	24,060	74,079	36,308	93,650
2025	31,300	105,379	50,448	144,098
2026	42,353	147,732	69,717	213,815
2027	55,747	203,479	86,294	300,109
2028	71,427	274,906	102,402	402,511
2029	97,856	372,762	118,219	520,730
2030	119,746	492,508	135,841	656,571
2031	151,757	644,265	149,301	805,872
2032	161,624	805,889	158,343	964,215
2033	170,919	976,808	166,702	1,130,917
2034	178,068	1,154,876	172,837	1,303,754
2035	177,093	1,331,969	170,779	1,474,533
2036	164,815	1,496,784	157,338	1,631,871
2037	152,557	1,649,341	143,878	1,775,749
2038	138,905	1,788,246	129,048	1,904,797
2039	125,713	1,913,959	114,860	2,019,657
2040	116,478	2,030,437	104,919	2,124,576
2041	101,479	2,131,916	89,850	2,214,426
2042	90,134	2,222,050	78,793	2,293,219
2043	78,214	2,300,264	67,911	2,361,130
2044	66,764	2,367,028	57,592	2,418,722
2045	55,930	2,422,958	47,888	2,466,610
2046	46,092	2,469,050	39,107	2,505,717
2047	37,251	2,506,301	31,254	2,536,971
2048	29,852	2,536,153	24,708	2,561,679
2049	23,784	2,559,937	19,412	2,581,091
2050	18,910	2,578,847	15,233	2,596,324


Cumulative Number of Electric Vehicles in-operation
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
-
Number of EVs
2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050
Base - cum
High - cum

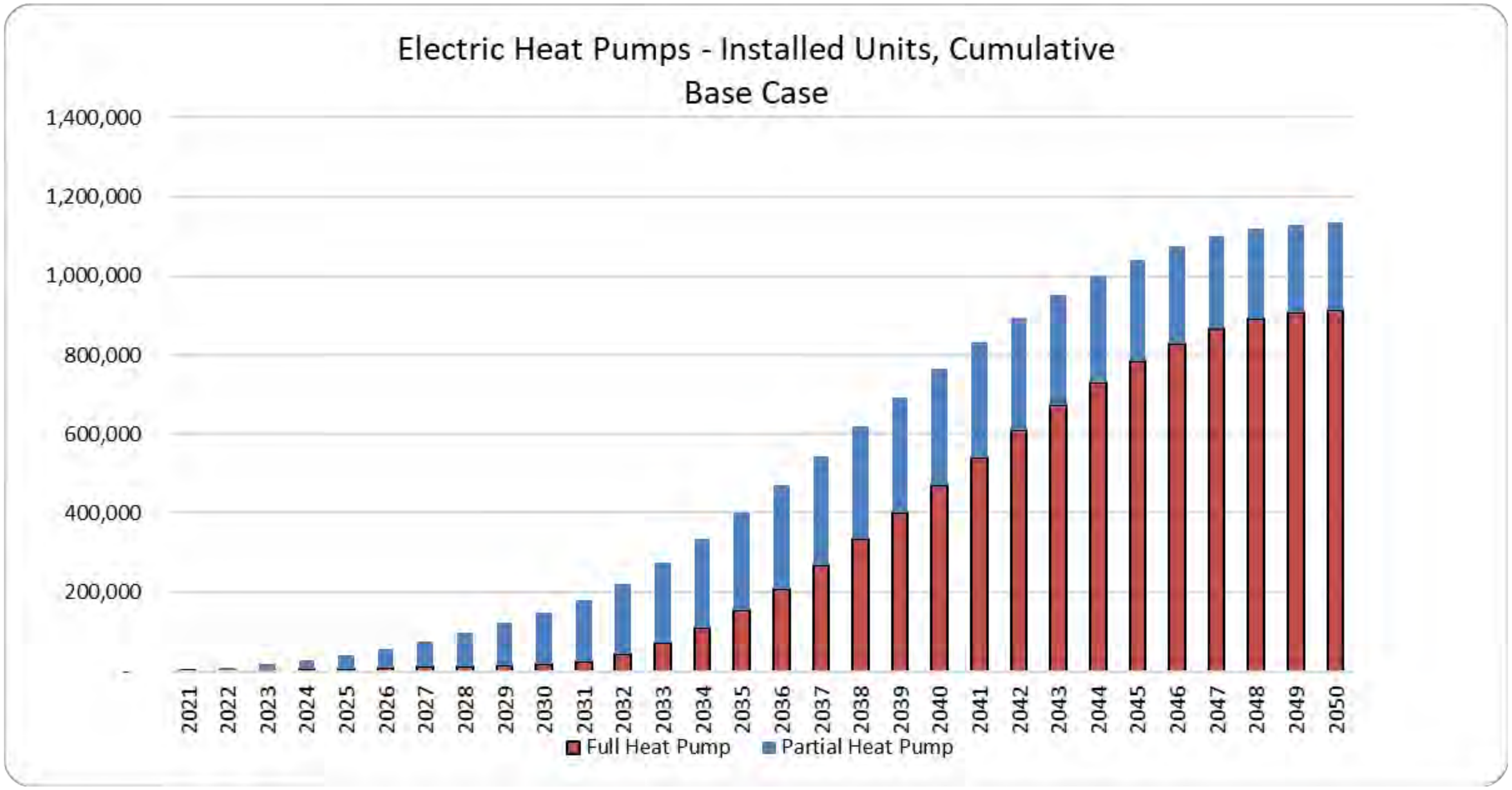
Electric Heat Pumps

(Number of Electric Heat Pumps)

Year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum
2019	849	849	849	849	849	849
2020	1,515	2,364	1,515	2,364	1,515	2,364
2021	1,957	4,321	1,957	4,321	1,957	4,321
2022	4,782	9,102	4,782	9,103	4,782	9,103
2023	8,238	17,341	8,238	17,341	8,238	17,341
2024	11,452	28,792	11,452	28,792	11,452	28,792
2025	11,427	40,219	11,992	40,785	12,886	41,678
2026	14,184	54,403	15,748	56,533	16,272	57,950
2027	16,800	71,203	19,084	75,617	25,132	83,082
2028	19,243	90,446	21,897	97,514	33,633	116,715
2029	21,482	111,928	24,099	121,613	41,654	158,369
2030	23,491	135,420	25,618	147,231	49,081	207,450
2031	27,240	162,660	31,821	179,052	55,807	263,257
2032	32,611	195,271	42,482	221,534	61,736	324,993
2033	37,501	232,773	51,947	273,482	66,784	391,777
2034	41,809	274,581	59,993	333,475	70,879	462,655
2035	45,443	320,024	66,434	399,909	73,962	536,617
2036	48,324	368,349	71,130	471,039	75,989	612,606
2037	50,388	418,737	73,985	545,024	76,932	689,538
2038	51,585	470,321	74,954	619,978	76,777	766,315
2039	51,881	522,202	74,065	694,043	75,526	841,841
2040	51,261	573,464	71,371	765,414	73,197	915,038
2041	49,728	623,192	67,335	832,748	69,824	984,862
2042	47,301	670,493	62,198	894,946	65,454	1,050,316
2043	44,018	714,511	55,937	950,883	60,150	1,110,466
2044	39,935	754,446	48,906	999,789	53,988	1,164,454
2045	35,122	789,567	41,424	1,041,213	47,055	1,211,509
2046	29,664	819,231	33,748	1,074,961	39,451	1,250,960
2047	23,660	842,891	26,063	1,101,024	31,283	1,282,243
2048	17,219	860,110	18,474	1,119,499	22,670	1,304,913
2049	10,461	870,571	11,015	1,130,513	13,733	1,318,645
2050	3,509	874,080	3,659	1,134,172	4,599	1,323,245



Cumulative Units
MW
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
2022
2023
2024
2025
2026
2027
Low - cum
Base - cum
High - cum



Electric Heat Pumps - Installed Units, Cumulative
Base Case
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
-
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
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2034
2035
2036
2037
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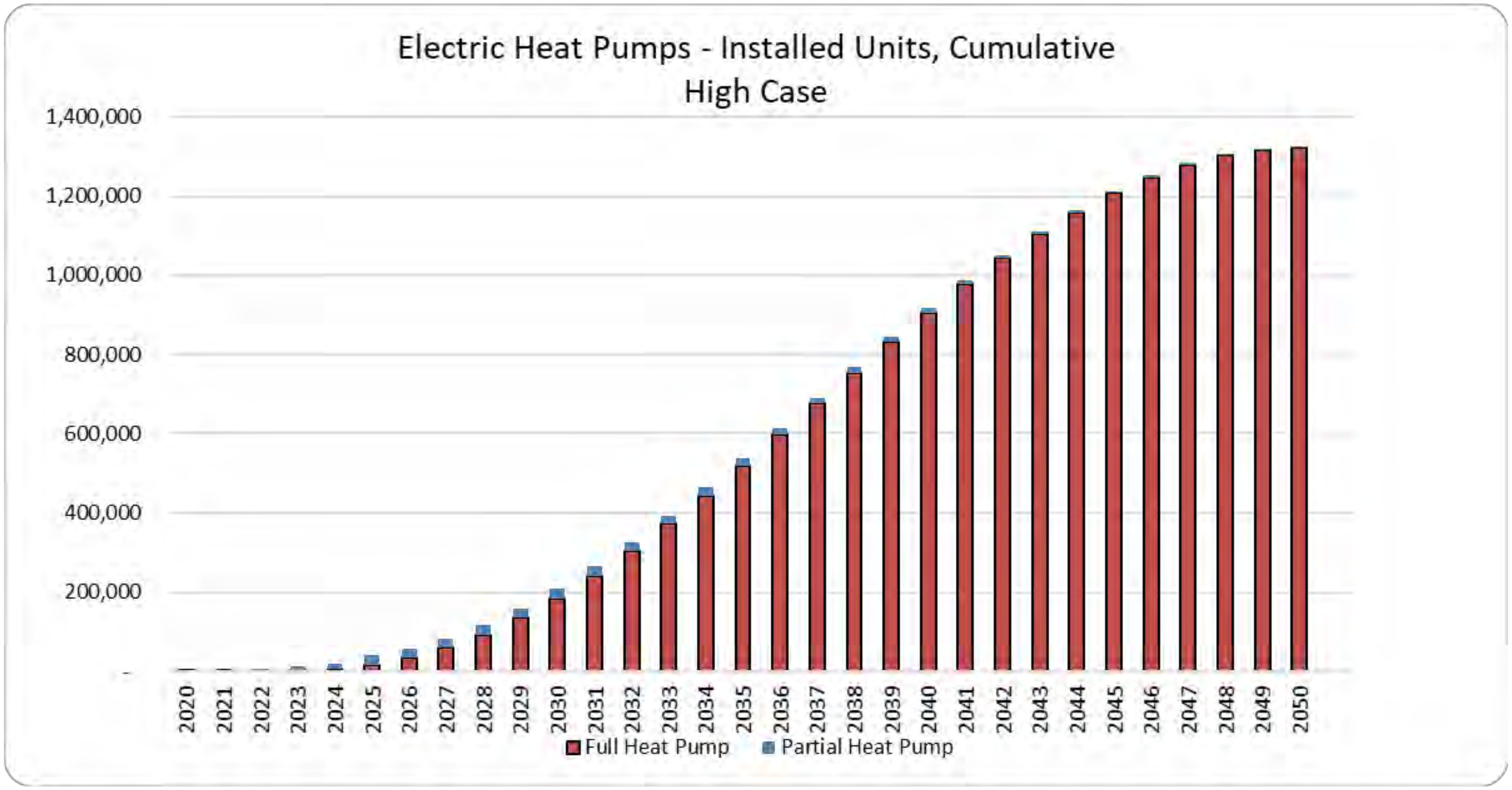
2041
2042
2043
2044
2045
2046
2047
2048
2049
2050
Full Heat Pump
Partial Heat Pump


Electric Heat Pumps - Installed Units, Cumulative
High Case
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
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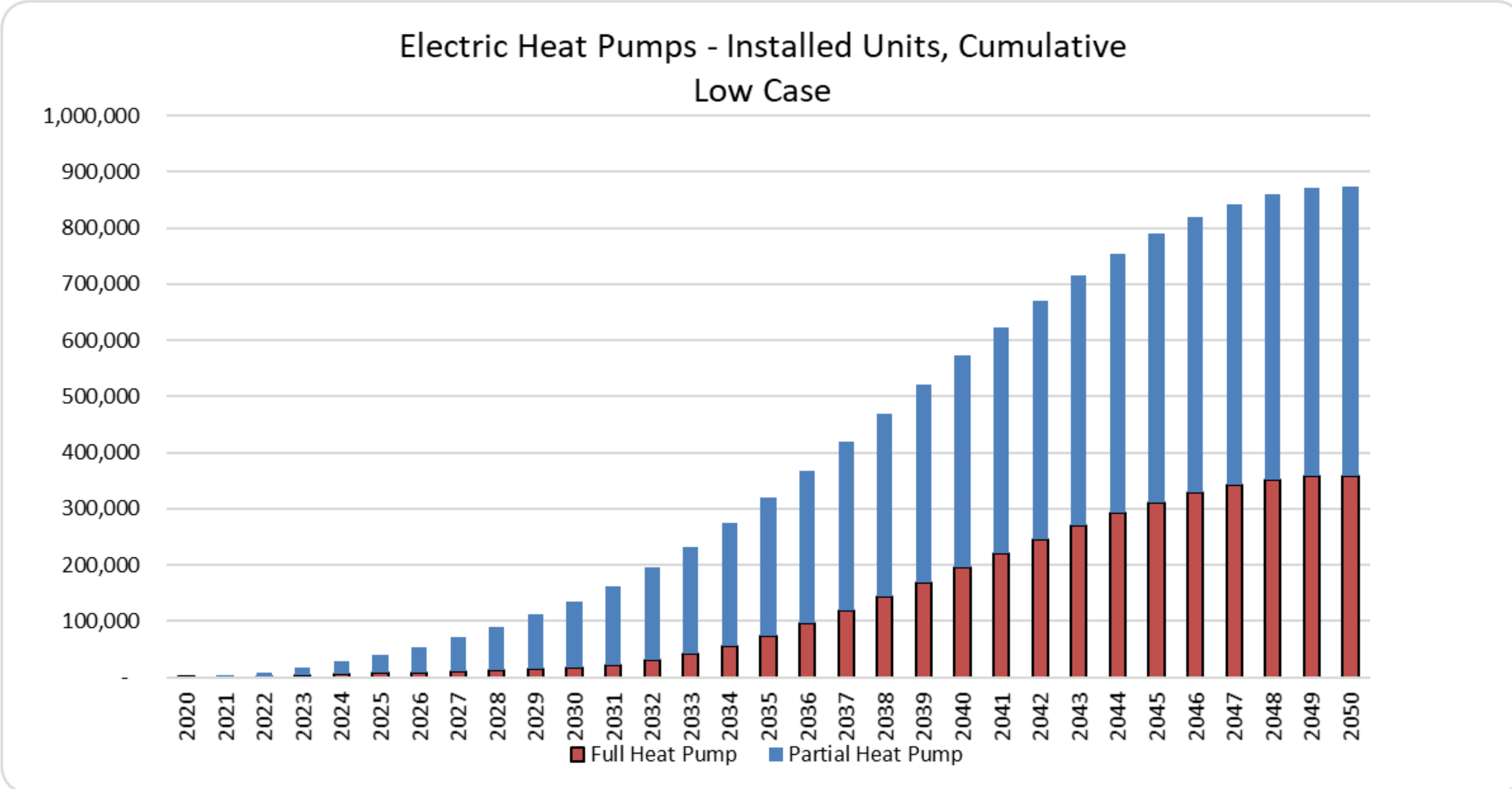
2047
2048
2049
2050
Full Heat Pump
Partial Heat Pump


Electric Heat Pumps - Installed Units, Cumulative
Low Case
1,000,000
900,000
800,000
700,000
600,000
500,000
400,000
300,000
200,000
100,000
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
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2031
2032
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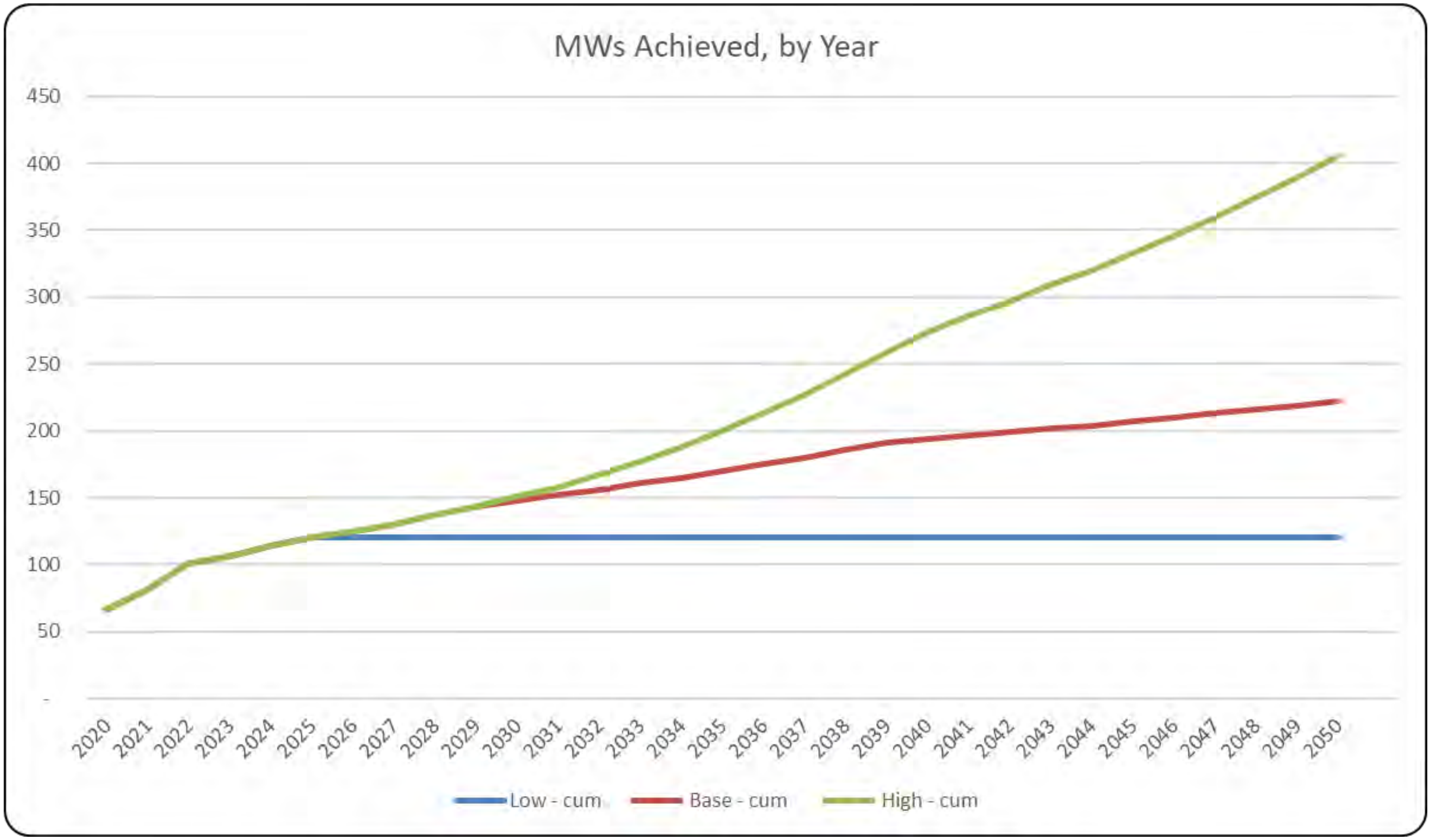
2041
2042
2043
2044
2045
2046
2047
2048
2049
2050
Full Heat Pump
Partial Heat Pump

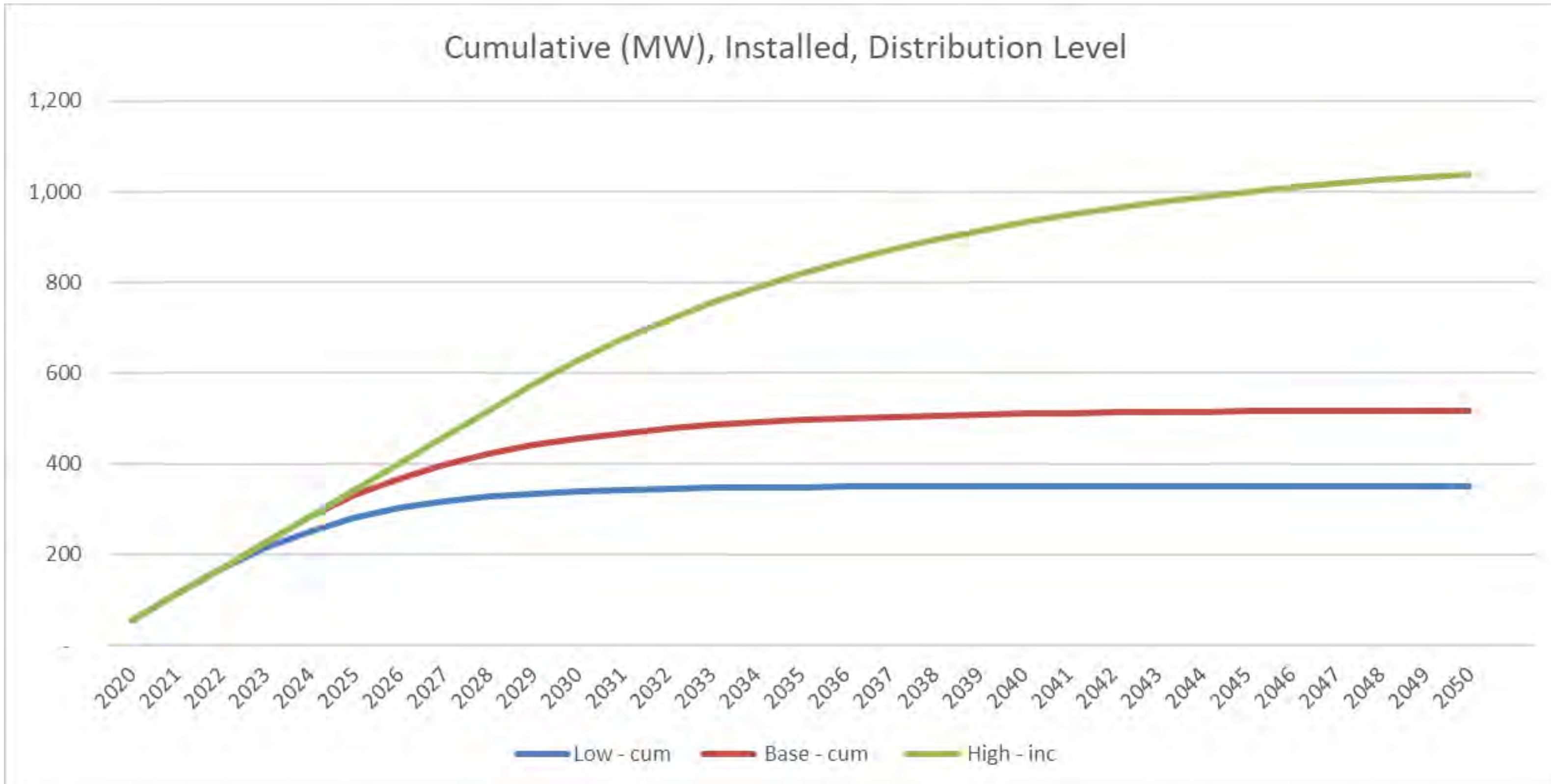
Demand Response

year	Low - cum	Base - cum	High - cum
2020	66	66	66
2021	81	81	81
2022	101	101	101
2023	106	106	106
2024	114	114	114
2025	120	120	120
2026	120	125	125
2027	120	130	130
2028	120	137	137
2029	120	143	143
2030	120	148	151
2031	120	152	158
2032	120	156	167
2033	120	161	177
2034	120	165	188
2035	120	170	200
2036	120	175	213
2037	120	180	227
2038	120	186	243
2039	120	191	259
2040	120	194	274
2041	120	197	286
2042	120	199	297
2043	120	202	309
2044	120	204	320
2045	120	207	333
2046	120	210	346
2047	120	213	360
2048	120	216	375
2049	120	219	389
2050	120	222	406


MWs Achieved, by Year
450
400
350
300
250
200
150
100
50
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
2046
2047
2048
2049
2050
Low - cum
Base - cum
High - cum

Energy Storage

year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum
2020	30	53	30	53	30	53
2021	58	111	58	111	58	111
2022	58	169	58	169	58	169
2023	46	215	58	227	58	227
2024	37	252	58	285	58	285
2025	30	282	46	331	58	343
2026	21	303	37	368	58	401
2027	15	318	30	398	58	459
2028	10	328	24	422	58	517
2029	7	335	19	441	58	575
2030	5	340	15	456	52	627
2031	3	343	12	468	47	674
2032	2	345	10	478	42	716
2033	2	347	8	486	38	754
2034	1	348	6	492	34	788
2035	1	349	5	497	31	819
2036	1	350	4	501	28	847
2037	-	350	3	504	25	872
2038	-	350	3	507	22	894
2039	-	350	2	509	20	914
2040	-	350	2	511	18	932
2041	-	350	1	512	16	948
2042	-	350	1	513	15	963
2043	-	350	1	514	13	976
2044	-	350	1	515	12	988
2045	-	350	1	516	11	999
2046	-	350	-	516	10	1,009
2047	-	350	-	516	9	1,018
2048	-	350	-	516	8	1,026
2049	-	350	-	516	7	1,033
2050	-	350	-	516	6	1,039



Cumulative (MW), Installed, Distribution Level
1,200
1,000
800
600
400
200
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
2046
2047
2048
2049
2050
Low - cum
Base - cum
High - inc

Appendix G: DER Scenarios Development

Energy Efficiency

Persistent and non-persistent savings are differentiated to correctly account for the accumulation of claimable savings over time. Non-persistent savings from behavioral programs like the home energy report do not accumulate over time. Home energy report savings are assumed to remain at the same level for each year of the planning cycle across all three cases. Savings from persistent programs do accumulate over time (i.e. lighting programs).

All EE savings are in adjusted gross terms.

Any savings from heat pumps and demand response programs are removed as they are projected separately.

Base

- The Company annual plans from the Subject Matter Experts (SMEs) are used for the short-term through 2024.
- Post-2024, the cumulative value of persistent EE savings is still expected to continue to grow but at a slower rate each year. The residential savings growth rate slows by 15% annually to account for saturation of claimable savings until 2035 and stays flat thereafter until 2050 whereas the commercial savings growth rate slows by 5% annually until 2050.

High

- For 2021, the incremental EE is equal to the base case and reflects the Company's annual plan.
- Post 2021, a declining annual incremental EE assumption is applied to the 2021 incremental commercial savings. The rate is at 5% to model a slower decline in claimable persistent savings. For residential savings, the incremental is 110% of the base case incremental savings value.

Low

- For 2021, the incremental EE is equal to the base case and reflects the Company's annual plan.
- Post-2021, incremental savings for residential and commercial from traditional EE programs are 75% of base case. This is the result of both rising EE baselines leading to lower levels of claimable savings and the shifting of resources to electrification of heat programs.

Solar -PV

Base

- The near-term prediction is based on the recent historical trend and SME's outlook on applications in the Company's queue and the assumption that National Grid will fill its share (i.e., 45%[23]) of the State's existing solar standards of 3.2 GW[24] by mid 2020s.
- In the longer-term, continuous growth is projected in order to achieve the National Grid's share (i.e., 45%) of the State policy target under the All Options scenario as stated in its 2050 decarbonization roadmap[25]. The All Options scenario targets a 6.99 GW of behind-the-meter (BTM) PV connection and a 16.2 GW of ground-mounted PV connection by 2050 for the State of Massachusetts. In this base case, it is assumed that all the BTM PV and 50% of the ground-mounted PV will be on the distribution system. It is then assumed that the Company will take its share of these. Thus, about 3.1 GW (6.9 GW * 100% * 45%) of BTM PV and 3.6 GW (16.2 GW * 50% * 45%) of ground-mounted PV are projected to be on the Company's distribution system by 2050.

High

- The near-term predictions are based on the SME's outlook for a stretching target and the assumption that the Company will achieve its estimated share of the State's existing solar standards at an earlier year than in the base case.
- In the longer term, the high case assumes the Company achieves its estimated share of the policy target of the All-Option scenario at a slightly early year.

Low

- The near-term predictions are based on the SME's outlook for a moderate connection case and the assumption that the Company will achieve its estimated share of the State's existing solar standards at a slightly later year than in the base case.
- In the longer term, the low case estimates the Company may achieve its estimated share of the policy target of the All-Option scenario at a slightly later year.

[23] 45% was the share for National Grid when the SMART program opened. It was the percentage of customers National Grid serves in the State of Massachusetts compared with Eversource and Unitil. This same share is assumed for calculating National Grid share of the State's existing and planned solar goals.
[24] *MA Clean Energy and Climate Plan for 2030*, page 68, June 2022.
[25] *Massachusetts 2050 Decarbonization Roadmap*, December 2020

Electric Vehicles

Light-duty Vehicles

Base

The base case is developed around California's Advanced Clean Car II (ACC-II)26 rules, which are expected to be adopted by Massachusetts. In the near-term, the zero-emission vehicle share of light-duty vehicle (LDV) sales is created based on the techno-economic potential and current market trends. In the medium-term (2026 -2030), the ACC-II rules have a range of possible outcomes, so the zero-emission vehicle sales share rises in line with the "flexibilities"27 (or lower-bound) of what the ACC-II rules require, reaching 59.5% in 2030. In the longer term (2031 and onward), zero emission vehicle sales match the ACC-II rules and reach 100% zero emissions vehicles in 2035 (and assume no more than 20% plug-in hybrid electric vehicles). Vehicle scrap is assumed based upon market data to develop the net EV in-operation numbers.

High

The high case is developed based upon the upper-bound of ACC-II rules for both near and long terms in which the zero-emission vehicle share of LDV sales is estimated to achieve 68% by 2030 and 100% by 2035.

Low

The low case is the same as the base case in terms of zero-emission vehicle sales share and growth rate, following the lower-bound of ACC-II rules in the near term, and trending to the upper-bound of ACC-II rules in 2026 and onward. It differs, however, from the base case in the EV charging profiles. While unmanaged charging is considered for the base case, the managed charging profile to mitigate the EV load impact on the peak demand is considered in the low case. For managed charging, it is assumed that 75% of the light-duty EV (LDEV) owners have access to the home chargers, and 75% of those do not charge their vehicles at home during the peak hours (4PM to 10PM). Away-from-home charging is assumed to continue unmanaged.

Medium-duty and Heavy-duty Vehicles, and E-buses

Base

The base case for the adoptions of medium-duty EV (MDEV), heavy- duty EV (HDEV) and E-buses is based on the California's Advanced Clean Trucks (ACT)28 rules through 2035 which have been adopted by the state. In the base case, the sales shares for MDEV, HDEV, and E-buses are estimated to be about 63%, 40%, and 75% of MDV, HDV, and buses, respectively, by the end of 2035. To extend the forecast until 2050, a similar growth rate is considered from 2036 to 2040, and after that 3% growth

[26] https://ww2.arb.ca.gov/rulemaking/2022/advanced-clean-cars-ii, retrieved September 2022

[27] Flexibilities include provisions to transfer ZEV "sales values" across all states that have adopted the regulations (e.g., a manufacturer can overachieve in California and underachieve elsewhere), provisions to sell affordable EVs in environmental justice areas, and using historical ZEV sales credits to meet the annual ZEV sales targets. All of the flexibilities provided in the rules expire by or before 2031.

[28] https://ww2.arb.ca.gov/our-work/programs/advanced-clean-trucks, retrieved September 2022

in sales share is assumed through 2050. That leads to 100%, 80%, and 100% sales shares for MDEV, HDEV, and E-Buses by the end of the forecast horizon, respectively.

High

The high case reflects an accelerated adoption rate. It is built on the base case where each year is multiplied by a growth factor. The growth factor is created to show 2% more increase in the sales share than the previous year until 2027. It will then increase to 3% through the end of the forecast horizon. That results in 85%, 54% and 100% sales shares for MDEV, HDEV, and E-Buses, respectively, by the end of 2035. All three sales shares reach to 100% by 2050.

Low

The low case is intended to show a slower growth rate than the base case. It is created based upon Bloomberg New Energy Finance's (BNEF) 2022 Electric Vehicle Outlook, which projects the MDEV, HDEV, and E-Buses in-operation shares through 2040. To extend the forecast until 2050, the Company extended the trend in the growth of EV sales for each vehicle type. The estimated vehicle-in-operation (VIO) shares for MDEV, HDEV, and E-Buses are about 14%, 18% and 63% by the end of 2035, respectively. The shares will increase to 51%, 63%, and 100% for MDEV. HDEV, and E-Buses by the end of the forecast horizon, respectively.

Combined forecasts

The overall base EV case is created by combining the base cases for LDEV, MDEV, HDEV, and E-buses. The overall high EV case combines the high case for LDEV, MDEV and HDEV and high E-bus case. The overall low EV case combines the low cases for LDEV, MDEV, HDEV, and E-buses.

Electric Heat

The three scenarios assume that the Company will meet the approved heat pump targets for the years 2022 to 2024.

Base Case:

Post 2024, the company assumes that Company's pro rata share of CECP PHASED pathway's target in 2050 will be met29. Thus, about 1.34 million of units will be installed by 2050 and about 80% of those will be installed as full applications. Penetration rates are expected to be about 86% of residential homes and 58% of commercial space heating capacity.

High Case:

Post 2024, the company assumes that Company's pro rata share of CECP Full Electrification pathway's target in 2050 will be met. In this case, the company would expect about 1.56 million full application heat pump installations by that year. This could represent the about 97% of penetration of all residential home and 88% of commercial space heating capacity in the commercial sector.

Low Case:

Post 2024, the company assumes that Company's pro rata share of CECP HYBRID pathway's target in 2050 will be met That would mean that about 1.03 mill. of heat pumps will be expected by 2050. The percentage of full applications in this scenario is lower than in other scenarios or 40% for the residential sector and 60% for the commercial sector.

[29] *Massachusetts Clean Energy and Climate Plan for 2025 and 2030*, June 2022

Demand Response

Base Case:

For the short term (i.e. until 2024), he forecast represents the projections developed by the Company's demand response SME. the approved Company targets from the SME Program Administrator for DR is used as the projection. Post year 2024, most technologies will growth annually at a decreasing rate. The annual average growth is approximately 2.5% over the forecast horizon[30].

High Case:

The high case is a continued incremental growth following the approved program years. Beginning in year 2025, most technologies will growth annually at a decreasing rate. The annual average growth is approximately 5.0% over the forecast horizon[33].

Low Case:

For the short-term, the approved Company targets from the SME Program Administrator for DR is used as the projections. Post year 2024, no additional incremental MW are added. It is assumed that the program's market potential is at its maximum and the projections are held constant through year 2050

[30] Exception: C&I Peak Savings is fixed for the entire forecast period at the 2022 level

Energy Storage

Base Case:

It was assumed that the Company would make a share of the statewide energy storage policy goals. In Massachusetts, the state policy is 1000 MWh by 202531. For summer peak impacts this is first converted to a MW equivalent using a four to one charging to peak output factor. Thus, the 1000 MWh target is about 250 MW. Only a portion of these is at the distribution level and will lower the load forecast (the remainder being considered supply by the ISO-NE and not considered in this load forecast). Based on the amount of energy storage installed in the state as of 2021, about 36.5% is considered distribution level and thus load reducing.

Based on this the storage targets considered load reducing are lowered to 92.5 MWs (37% * 250) by year 2025. The Company's share of storage as in the state as of this year is about 78%. This is assumed to persist through year 2025. Thus, it is assumed that the year 2025 target for the Company is 72.15 MW (78% * 150). Not all energy storage will help to reduce the Company's summer peaks. A number of customers may use their storage to serve their own needs and times. It is assumed that only 85% of the installed energy storage amounts will impact the peak load. Thus, the final year 2025 target for peak reducing storage is 61.3 MW (85% * 72.15).

Current proposed forecast projects 282 MW (low case), 331 MW (base case) and 343 MW of energy storage by 2025 in the company' service territory. All projections are well above the inferred company's share in the state 2025 goal.

Massachusetts does not currently have explicit energy storage targets beyond year 2025. However, the state has published two studies, one the Clean Energy and Climate Plan for 2030 (CECP) and two the "Energy Pathways to Deep Decarbonization 2050". In the 2050 document, there are several scenarios that can guide the state to meeting its year 2050 long-term Climate goals. For example, by the year 2050, the "All options" scenario implies about 3,000 MW of large-scale energy storage (generation), "100% Renewable" scenario implies about 4,000 MW and the "No thermal" scenario implies 12,000 MW32.

The company used those inferred long-run energy storage capacity to provide a context to its long-term forecast at the distribution level. In order to do that, the company made two assumptions in the long run: (a) the company 'share of energy storage in the state will approximate the company's load share in the state (45%) and (b) more energy storage will move towards the supply side and less new storage as distribution level load reductions. The longer-term distribution share is assumed to drop to 20% (vs. 37% now). By using these assumptions, the current company's long term energy storage installed capacity forecast in 2050 will relate to the different pathways from "Energy Pathways to Deep Decarbonization 2050 as follows: the low case forecast of 351 MW will be close to the "All Options" scenario, the base case forecast of 516 MW will be between "All Options" and "100% renewable" scenarios and finally, the high case forecast of 1,040 MW will be between "100% Renewables" and "No Thermal" scenarios, but closer to the later.

[31] https://www.mass.gov/info-details/esi-goals-storage-target

[32] *Energy Pathways to Deep Decarbonization. A Technical Report of the Massachusetts 2050 Decarbonization RoadMap*. Page 61, December 2020

Finally, it is assumed the long-term peak reducing estimate will remain at 85% (85% is based on similar findings in New York which have significant pricing signals during peak hours). For the base case scenario, this lowers the final target to 439 MW by year 2050 (85% * 516).

The actual projections for installed energy storage are as follows. As of the end of year 2021 there was about 111 MW installed in the Company's service territory, about 58 MW of which was installed in the year 2021 alone. The base case assumes a continuation of this 58 MW per for the next three years, before assuming some saturation. Saturation is assumed to be 20% less per year for each subsequent year forward. This puts the Company on a path to easily surpass both the year 2025 and year 2050 targets determined above. Thus, it can be said that the Company is on-target for the CECP 2030 goals for this DER.

High Case:

The high case is similar to the base case, however, the 58 MW per year of new installations continues to year 2030. Then, saturation is assumed to be 10% less per year for each subsequent year forward up to 2050.

Low Case:

The low case assumes that saturation begins in 2023 already and at level of 20-30% less new installations each year. It is noted that this drop-off may not necessarily mean that total energy storage installations are dropping off, but instead that more have moved from the distribution level (which is the focus of this forecast) to the bulk system, supply side (which would not be included in this forecast).

Exhibit 9C: Detailed reports on National Grid's Load Forecasting

MASSACHUSETTS ELECTRIC DISTRIBUTION

FY2024 to FY2028 Forecast

GWh Deliveries & Customer Counts

(Revenue & Rate Class)

[Massachusetts Electric Company]
[Nantucket Electric Company]

October 2022

Economics & Load Forecasting
Advanced Data & Analytics

REVISION HISTORY & GENERAL NOTES

Revision History

Version	Date	Changes
Original	10/18/2022	- ORIGINAL
Rev1	10/28/2022	- updated EV profiles for medium- and heavy-duty vehicles and E-buses, which impacted the forecasts for the commercial and industrial sectors - updated EH counts being considered

General Notes:

- Historical data through August 2022; projections from September 2022 forward.
- Economic data is from Moody's vintage August 2022.
- Energy pricing, energy efficiency, electric heating, and solar data is internal data vintage August 2022.
- Electric Vehicle data is POLK data vintage December 2021.
- Source data for retail deliveries is the internal CSS billing system aggregate monthly reports.
- "Weather-Normal" is based on the ten-year average of monthly degree days from years 2012 to 2021.
- The modeling process employs a "reconstruction" for DERs in the historical input data set.

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1. Summary

U.S. Electric Distribution System

National Grid's U.S. electric distribution system is comprised of three companies serving over 3 million customers in Massachusetts and upstate New York. The three electric distribution companies are Massachusetts Electric Company and Nantucket Electric Company, serving 1.35 million customers in Massachusetts; and Niagara Mohawk Power Company, serving 1.7 million customers in Upstate New York.

Massachusetts Electric Company

Massachusetts Electric Company (MECO) makes up 36% of electric deliveries in the U.S. for National Grid. Figure 1 shows National Grid's service territory in the U.S.[1].

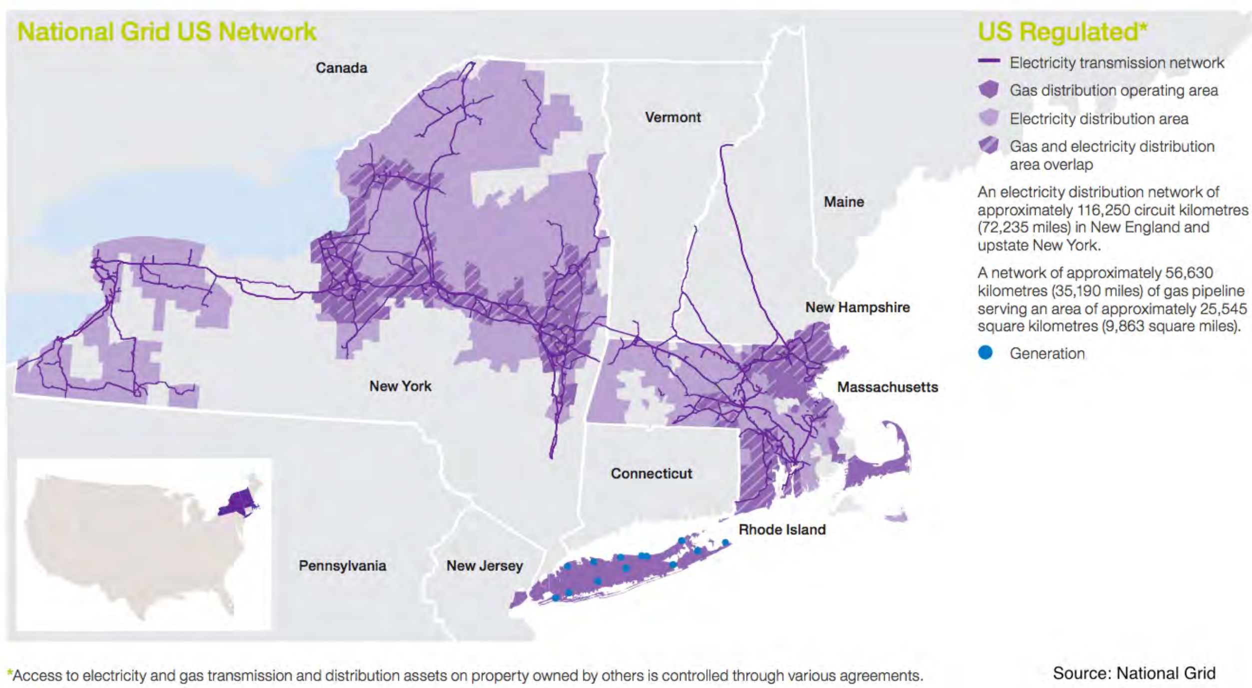

Figure 1: National Grid Service Territory[1]

MECO's service territory is approximately 43% residential, 44% commercial and 13% industrial by volume. It spans across the entire state, including all or some portions of all counties, except Dukes and Barnstable counties.

From fiscal year 2018 to fiscal year 2023, Massachusetts Electric weather normalized deliveries averaged a 0.8% annual <u>decline</u>. For the fiscal year 2023 to date, i.e. from April 2022 to August

[1] As of May 22, 2022, National Grid has completed the sale of The Narragansett Electric Company ("NECO") to PPL Rhode Island Holdings, LLC. Thus, Rhode Island is not part of National Grid's U.S. electric distribution system after the completion of the sale.

2022, and what is expected for the remainder of the fiscal year (through March 2023), the total energy is expected to grow 0.7% from the previous fisical year. Residential deliveries are expected to increase by 1.4%, commercial deliveries are expected to remain similar as the previous fisical year, and industrial deliveries are expected to increase by 1.0%.

In the next five calendar years, the annual deliveries are expected to continue to grow by 1.0% after impacts for Distributed Energy Resources (DERs). The DERs included are energy efficiency (EE) programs, solar-photovoltaics (PV), electric vehicles (EV), and electric heat pumps (EH). Before the impacts of these DERs, it is projected that growth would have been positive 1.4% per year.

Figure 2 shows the annual total energy in both GWh and annual percent change. The energy is expected to grow year over year for the five-year forecast horizon. The residential sector is expected to grow year over year between FY2024 and FY2028 with customer counts and residential usage being expected to grow and net DER reduction being expected to decrease (due to the electrifications in the transportation and heating sectors) in later years. The commercial sector is expected to continue to grow post the pandemic but at a more stable and sustainable rate comparing to FY2022. The industrial sector is expected to show decline aligning with its long-term historical trend. Table 1 shows total historical and forecast deliveries by revenue class for the Massachusetts Electric Company.

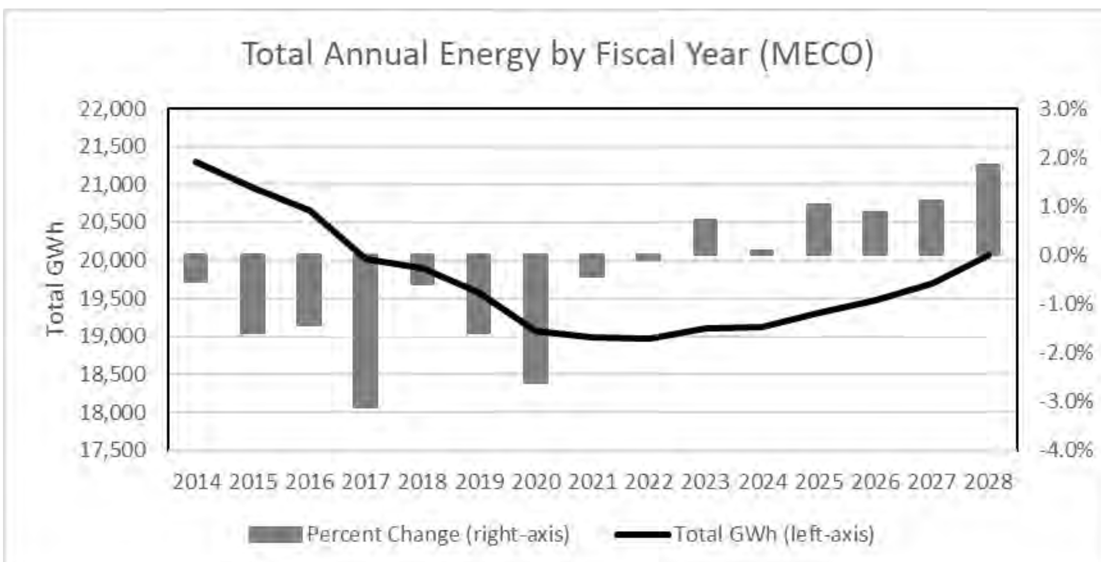

Figure 2: Annual Total Energy by Fiscal Year

Table 1: Total historical and forecasted deliveries by revenue classes (MECO)

ANNUAL GWh (*and percent growth*) FISCAL YEAR (Historicals & Projections: Weather-Normal) by Revenue Class
After Energy Efficiency, Solar and Electric Vehicle Impacts

FISCAL YEAR	RESIDENTIAL Non-Heating		Elec Heating		RESIDENTIAL Total		COMMERCIAL		INDUSTRIAL		StreetLighting & Other		M		TOTAL	
2008	7,708.3		945.2		8,653.5		9,443.7		3,766.2		110.2		10.3		21,973.5	
2009	7,649.1	-0.8%	919.5	-2.7%	8,568.6	-1.0%	9,439.6	0.0%	3,703.1	-1.7%	110.2	0.0%	9.9	-4.2%	21,821.5	-0.7%
2010	7,737.6	1.2%	906.9	-1.4%	8,644.5	0.9%	9,257.1	-1.9%	3,394.8	-8.3%	109.0	-1.1%	9.5	-3.6%	21,405.4	-1.9%
2011	7,831.8	1.2%	903.4	-0.4%	8,735.2	1.0%	9,177.5	-0.9%	3,362.5	-1.0%	108.7	-0.2%	9.7	2.5%	21,384.0	-0.1%
2012	7,874.2	0.5%	895.5	-0.9%	8,769.7	0.4%	9,221.0	0.5%	3,268.8	-2.8%	108.4	-0.3%	9.0	-8.0%	21,368.0	-0.1%
2013	7,991.1	1.5%	895.4	0.0%	8,886.4	1.3%	9,218.6	0.0%	3,203.3	-2.0%	109.4	0.9%	9.3	3.5%	21,417.7	0.2%
2014	8,014.6	0.3%	898.6	0.4%	8,913.2	0.3%	9,141.9	-0.8%	3,140.8	-2.0%	106.6	-2.6%	9.6	3.3%	21,302.5	-0.5%
2015	7,737.7	-3.5%	872.1	-2.9%	8,609.8	-3.4%	9,095.6	-0.5%	3,145.9	0.2%	110.4	3.6%	8.6	-10.5%	20,961.8	-1.6%
2016	7,512.6	-2.9%	824.1	-5.5%	8,336.7	-3.2%	9,134.9	0.4%	3,080.5	-2.1%	107.8	-2.4%	6.7	-22.0%	20,659.8	-1.4%
2017	7,337.1	-2.3%	796.5	-3.3%	8,133.7	-2.4%	8,924.3	-2.3%	2,853.1	-7.4%	103.5	-4.0%	7.1	6.2%	20,014.5	-3.1%
2018	7,320.9	-0.2%	801.9	0.7%	8,122.8	-0.1%	8,896.3	-0.3%	2,776.6	-2.7%	99.6	-3.8%	6.4	-9.5%	19,895.2	-0.6%
2019	7,277.8	-0.6%	782.7	-2.4%	8,060.4	-0.8%	8,815.3	-0.9%	2,623.1	-5.5%	80.5	-19.2%	6.9	7.1%	19,579.3	-1.6%
2020	7,043.8	-3.2%	763.4	-2.5%	7,807.3	-3.1%	8,671.5	-1.6%	2,511.5	-4.3%	75.4	-6.3%	6.3	-9.0%	19,065.7	-2.6%
2021	7,686.1	9.1%	774.2	1.4%	8,460.3	8.4%	8,039.9	-7.3%	2,421.3	-3.6%	59.1	-21.6%	6.1	-2.0%	18,980.6	-0.4%
2022	7,380.0	-4.0%	763.3	-1.4%	8,143.3	-3.7%	8,330.9	3.6%	2,433.9	0.5%	56.0	-5.2%	6.0	-1.9%	18,964.1	-0.1%
2023	7,514.9	1.8%	739.6	-3.1%	8,254.4	1.4%	8,327.0	0.0%	2,458.1	1.0%	60.5	8.0%	6.0	-1.0%	19,100.1	0.7%
2024	7,511.8	0.0%	765.2	3.5%	8,277.1	0.3%	8,346.2	0.2%	2,427.5	-1.2%	64.2	6.1%	6.0	0.0%	19,114.9	0.1%
2025	7,649.2	1.8%	780.5	2.0%	8,429.7	1.8%	8,418.8	0.9%	2,401.3	-1.1%	63.6	-0.9%	6.0	0.0%	19,313.4	1.0%
2026	7,781.5	1.7%	796.5	2.0%	8,578.0	1.8%	8,483.6	0.8%	2,359.2	-1.8%	63.0	-0.9%	6.0	0.0%	19,483.8	0.9%
2027	7,951.9	2.2%	817.8	2.7%	8,769.7	2.2%	8,554.8	0.8%	2,312.2	-2.0%	62.4	-0.9%	6.0	0.0%	19,699.1	1.1%
2028	8,207.0	3.2%	847.2	3.6%	9,054.2	3.2%	8,666.8	1.3%	2,277.9	-1.5%	61.9	-0.9%	6.0	0.0%	20,060.8	1.8%
Annual Growth Rates:																
prior 15 years		-0.2%		-1.6%		-0.3%		-0.8%		-2.8%		-3.9%		-3.6%		-0.9%
prior 10 years		-0.6%		-1.9%		-0.7%		-1.0%		-2.6%		-5.8%		-4.3%		-1.1%
prior 5 years		0.5%		-1.6%		0.3%		-1.3%		-2.4%		-9.5%		-1.5%		-0.8%
BASE YEAR:		**2023**														
next 5 years		1.8%		2.8%		1.9%		0.8%		-1.5%		0.5%		0.0%		1.0%

Nantucket Electric Company

The Nantucket Electric Company comprises less than 1.0% of total U.S. deliveries for National Grid. The company's Nantucket service territory is approximately 68% residential and 32% non-residential. It covers the whole island.

Nantucket weather normalized deliveries growth from fiscal year 2018 to fiscal year 2023 averaged <u>negative</u> 2.3% per year.

In the next five calendar years, annual growth is expected to continue to <u>grow</u> by 0.9% after impacts for Distributed Energy Resources (DERs). The DERs included are energy efficiency (EE) programs, solar-photovoltaics (PV) and electric vehicles (EV) for all sectors, and electric heat pumps (EHP) for the residential sector only. Before the impacts of these DERs, it is projected that growth would have been the same <u>positive</u> 1.2% per year.

Figure 3 shows the annual total energy in both GWh and annual percent change. The energy is expected to grow for the five-year forecast horizon.

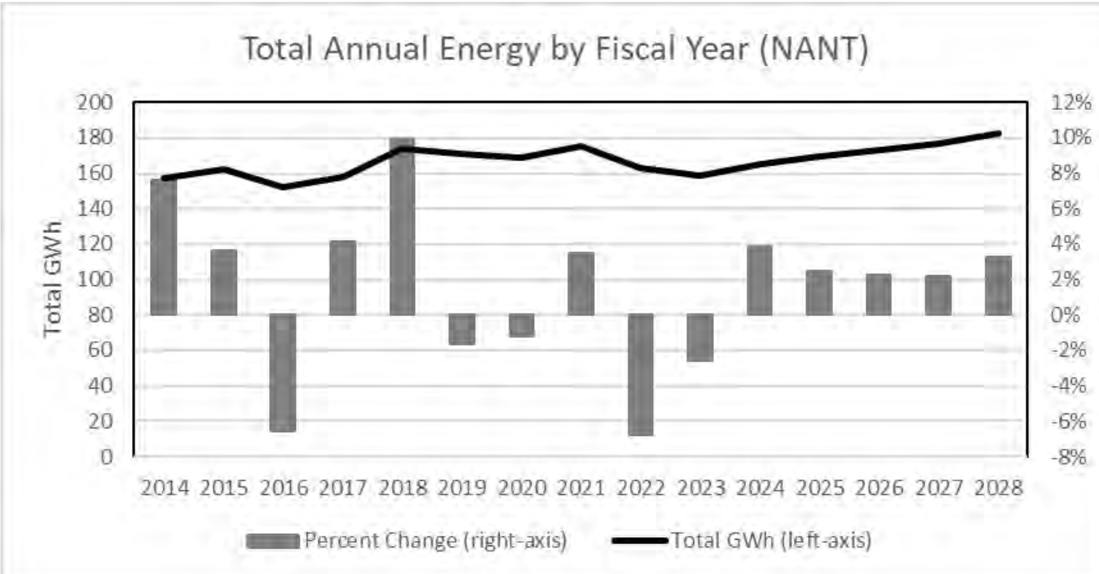

Figure 3: Annual Total Energy by Fiscal Year

Table 2 shows total historical and forecast deliveries for Nantucket Electric.

Table 2: Total historical and forecasted deliveries by revenue classes (Nantucket)

ANNUAL GWh (*and percent growth*) FISCAL YEAR (Historicals & Projections: Weather-Normal) by Revenue Class

After Energy Efficiency, Solarr, Electric Vehicle, and Electric Hear Pump Impacts

FISCAL YEAR	RESIDENTIAL Non-Heating		Elec Heating		RESIDENTIAL Total		COMMERCIAL		INDUSTRIAL		StreetLighting & Other		TOTAL	
2008	93.3		1.9		95.3		49.4		0.8		0.3		145.8	
2009	92.1	-1.3%	1.7	-9.8%	93.8	-1.5%	49.1	-0.6%	0.9	9.2%	0.3	8.1%	144.1	-1.1%
2010	92.1	0.0%	1.7	-1.7%	93.8	-0.1%	50.7	3.2%	1.0	4.3%	0.3	-1.3%	145.7	1.1%
2011	88.1	-4.3%	1.5	-14.6%	89.6	-4.5%	48.8	-3.8%	1.0	6.2%	0.3	-1.7%	139.6	-4.1%
2012	91.6	3.9%	1.5	3.5%	93.1	3.9%	50.1	2.7%	1.0	1.9%	0.3	0.2%	144.5	3.5%
2013	93.5	2.0%	1.5	-0.1%	95.0	2.0%	49.5	-1.2%	1.0	-2.5%	0.3	-0.3%	145.7	0.8%
2014	101.7	8.8%	1.7	10.7%	103.4	8.8%	52.2	5.6%	1.0	-6.1%	0.3	1.1%	156.8	7.6%
2015	105.4	3.6%	1.7	1.5%	107.1	3.6%	54.2	3.9%	0.9	-1.6%	0.3	-0.9%	162.5	3.7%
2016	98.4	-6.6%	1.6	-8.3%	100.0	-6.6%	50.6	-6.7%	1.0	10.6%	0.3	-0.1%	151.9	-6.5%
2017	104.3	5.9%	1.6	1.9%	105.8	5.9%	51.2	1.1%	1.0	-7.8%	0.3	0.1%	158.2	4.2%
2018	111.4	6.8%	1.7	9.1%	113.1	6.9%	59.8	17.0%	0.7	-24.9%	0.3	0.4%	173.9	9.9%
2019	111.1	-0.3%	1.7	-3.9%	112.8	-0.3%	57.4	-4.1%	0.7	-3.5%	0.3	1.0%	171.1	-1.6%
2020	112.5	1.3%	1.6	-0.9%	114.2	1.2%	53.9	-6.0%	0.6	-7.6%	0.3	-1.2%	169.0	-1.2%
2021	118.7	5.5%	1.7	2.0%	120.4	5.5%	53.7	-0.5%	0.6	-9.0%	0.3	-0.3%	174.9	3.5%
2022	110.1	-7.3%	1.5	-8.6%	111.6	-7.3%	50.6	-5.8%	0.7	18.9%	0.3	-0.6%	163.1	-6.8%
2023	108.1	-1.8%	1.4	-6.8%	109.6	-1.8%	48.4	-4.4%	0.8	12.7%	0.2	-8.0%	158.9	-2.6%
2024	111.5	3.1%	1.4	0.8%	113.0	3.1%	51.1	5.7%	0.7	-5.0%	0.3	9.3%	165.1	3.9%
2025	114.5	2.7%	1.5	4.6%	116.1	2.7%	52.1	2.0%	0.7	-2.0%	0.3	0.0%	169.2	2.5%
2026	117.4	2.5%	1.6	4.0%	119.0	2.5%	53.1	1.8%	0.7	-1.9%	0.3	0.0%	173.0	2.3%
2027	120.2	2.4%	1.6	3.0%	121.8	2.4%	54.0	1.8%	0.7	-1.8%	0.3	0.0%	176.8	2.2%
2028	124.4	3.5%	1.7	4.1%	126.1	3.5%	55.5	2.7%	0.7	-1.7%	0.3	0.0%	182.6	3.3%
Annual Growth Rates:														
prior 15 years		1.0%		-2.0%		0.9%		-0.1%		-0.5%		-0.3%		0.6%
prior 10 years		1.5%		-0.5%		1.4%		-0.2%		-2.6%		-0.9%		0.9%
prior 5 years		-0.6%		-3.7%		-0.6%		-4.2%		1.7%		-1.9%		-1.8%
BASE YEAR:	**2023**													
next 5 years		2.9%		3.3%		2.9%		2.8%		-2.5%		1.8%		2.8%

1.1. Forecast Methodology

The Company's electric deliveries and customer counts forecast is developed from econometric models relating monthly deliveries by company and class of service to regional economic and/or demographic variables, weather, and other explanatory variables. The models estimate the historical relationship between deliveries and these variables. The models then predict future deliveries based on forecasts of the explanatory variables. The total residential, residential electric heating, and commercial models are specified as energy use-per-customer models. Separate models are developed for customer counts. The use-per-customer model results are multiplied by the customer count model results to determine overall energy deliveries. The industrial models are specified directly as total deliveries.

All energy models are specified after reconstituting the historical deliveries for Distributed Energy Resources (DER). That is, after adding back the impacts of these DERs to the historical input dataset. The DER that are included are: energy efficiency (EE), solar-PV (PV), electric vehicles (EV), and electric heat pumps (EH). The model-produced GWh delivery forecast results are then adjusted to reflect projected cumulative DER impacts.

Class of service deliveries and customer forecasts are allocated to rate classes based on historical trends.

All models are checked for overall goodness of fit and statistical validity.

1.2. Regional Economic Drivers

The historical and forecast economic explanatory variables are obtained from Moody's Analytics. Moody's provides economic forecasts at the U.S., state, metro, and county levels. The Company aligns these areas with each operating company to develop load forecasts. Key economic drivers are number of households for the customer counts forecasting in the residential and commercial sectors, manufacturing employment for the customer counts forecasting and energy forecasting in the industrial sector, and gross state product (GSP) for energy usage per customer count forecasting in the commercial sector. Time trend is used for the residential energy usage per customer count forecasting. The Moody's Baseline forecast released in August 2022 was used. The forecast assumes that the Federal Reserve will continue to raise interest rates until it reaches its inflation target in early 2024. The economy should reach full employment later this year, which enables the Federal Reserve to continue with its quantitative tightening policy. High inflation is largely due to higher energy and commodity prices brought on by the recent geo-political actions and the lingering supply chain constraints. The forecast assumes a modest increase in oil prices in the fourth quarter before they steadily decline in 2023 and the first half of 2024. Oil prices bottom in 2024, a touch below $65 per barrel and each new wave of COVID-19 is assumed to be less disruptive to the supply chain than the preceding wave.The Inflation Reduction Act (IRA), which passed the Senate recently, has been incorporated in the August baseline forecast. The IRA is estimated to reduce U.S. inflation, as measured by the consumer price index, by 3.3 basis points per year on average over the next 10 years.The forecast also assumes that the economic activity is not severely hampered by COVID-19 and the case counts will remain below the peak in January 2022 due to widespread vaccinations and new treatments. Overall, real Gross Domestic Product (GDP) growth is forecast to rise by 1.6% in 2022, by 1.5% in 2023 and averaging about 2.8% per year between 2024-2027. Though the U.S. labor market remains very strong, it is set to moderate. The forecast is for the unemployment rate to gradually increase in the second half of 2022, averaging 3.7% in the fourth quarter. The unemployment rate keeps rising in 2023 because of below-potential GDP growth and job growth and is expected to average 4.0% for the years 2024-2027.

The figures below show economic indicators for each of the Companies in each of the service territories in the Northeast in addition to the U.S. overall. This provides comparative values to the subject service territory.

Figure 4 summarizes Moody's forecast for number of households. Households can provide an indication of the overall load growth in a region as more households can translate into more residential load as well as more commercial load as more consumers support the local economy. In the year 2023, it is expected to remain a similar growth rate as in the previous two years. For the rest of the planning horizon, the region's number of households is expected to continue the growth at a rate that is less than the national average.

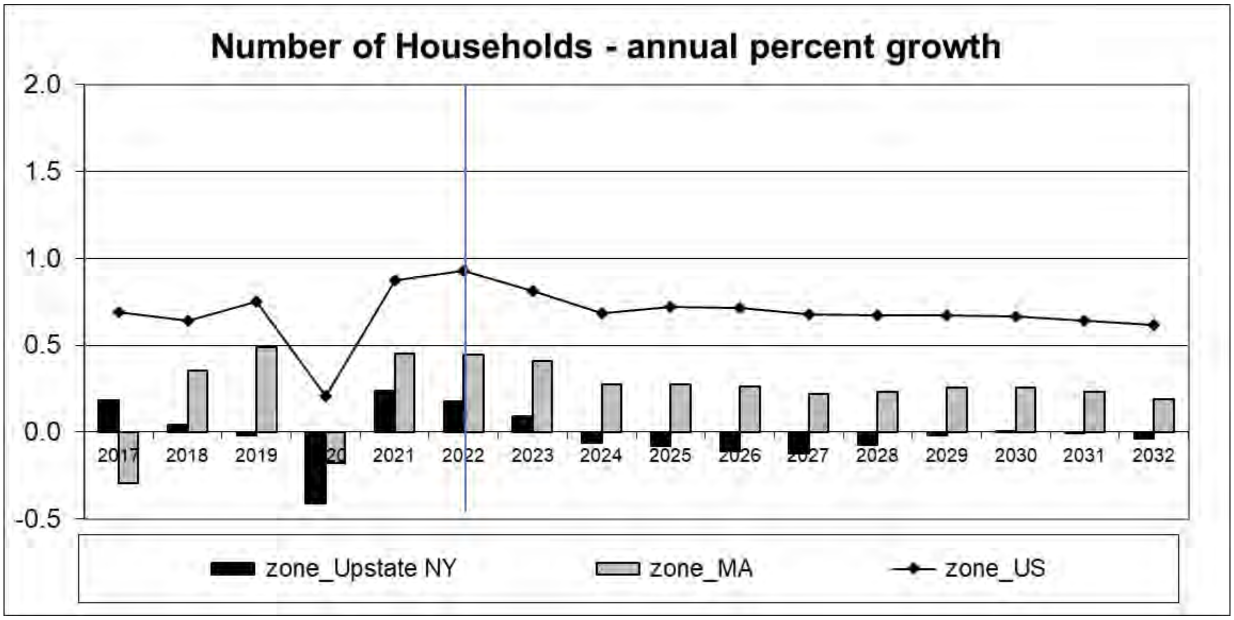

Figure 4: Number of households growth of Upstate NY, MA, and the U.S.

Figure 5 summarizes the forecast for gross state product (GSP). GSP can provide an overall indication of the strength of the economy. A stronger economy can translate to more load in all sectors, notwithstanding the offsetting impacts of DERs. Annual growth in MA significantly declined in 2020 due to the pandemic, and strong rebound was observed in 2021 and remained grow in 2022. For the planning horizon, the growth rate settles into between two and three percent per year that is about the same as the U.S.

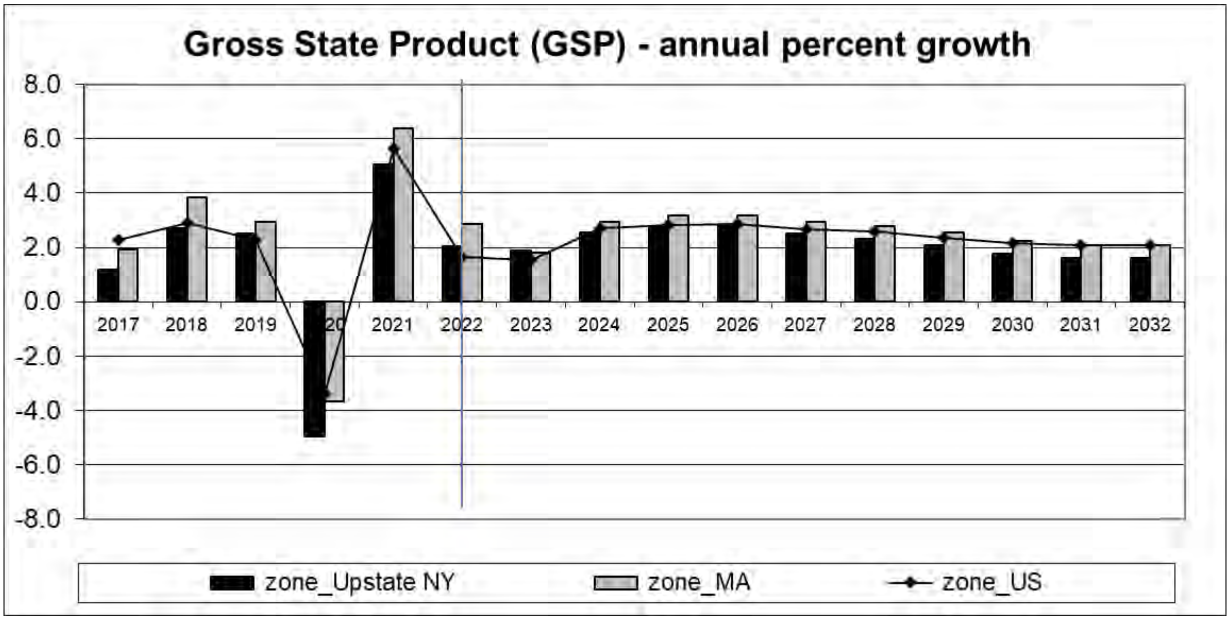

Figure 5: GSP growth of Upstate NY, MA, and the U.S.

Figure 6 summarizes the forecast for manufacturing employment. All regions and the country experienced recovery in 2021 and 2022 from the significant decline in the year 2020. Some growth is projected for the next two years, and then it is expected to return to a longer-term negative growth less than 1.0% per year. This longer-term trend is consistent with the region's longer-term historical trend.

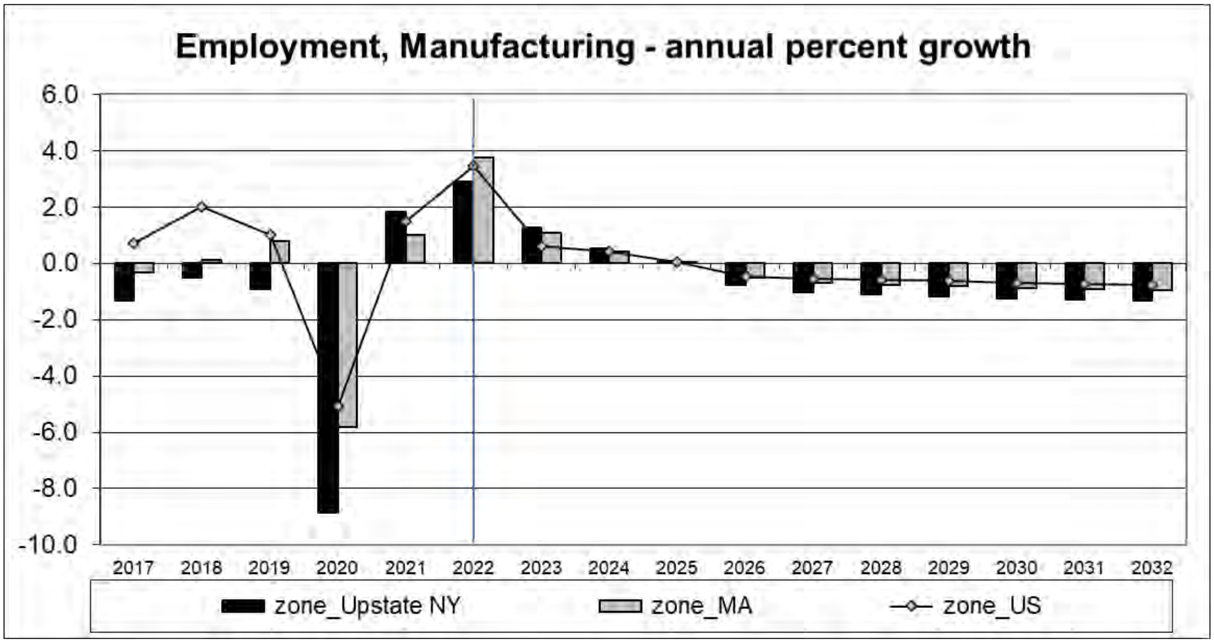

Figure 6: Manufacturing employment growth of Upstate NY, MA, and the U.S.

Nantucket Island tends to run higher economically for all categories compared to the state overall.

1.3. Weather Assumptions

Weather data is collected from the major weather stations located within the Company's service territory and used to model, forecast, and weather-normalize GWh deliveries. The relevant weather stations are Boston, Worcester, Nantucket, Providence (due to its proximity to southeastern Massachusetts) and Albany (due to its proximity to western Massachusetts). These most closely represent the company's service territory.

Seasonal heating and cooling degree days are used to model the relationship between energy deliveries and weather. Cooling degree-days (CDD) are equal to average daily temperature minus 65 degrees (however no less than zero). The more CDDs over a given period, the hotter the daily temperatures are. Heating degree-days (HDD) are equal to 65 degrees minus average daily temperature (but no lower than zero). The more HDDs over a given period, the colder it is.

Since customers are billed on a cycle throughout the month, billed GWh deliveries reflect energy consumed during part of the current month and part of the previous month. HDDs and CDDs must reflect this same consumption pattern. This is accomplished by using meter reading schedules to match daily degree days with the days between reading dates for each one of the 20 billing cycles, then taking the average of degree days over the 20 cycles.

The forecast report provides historical data in terms of actual and weather-adjusted (or weather-normalized) energy results. It also provides future projections on a weather-normalized basis. Results are weather-normalized by taking the ten-year average of HDD and CDD and incorporating these into the regression models. By updating the normal values each year with the most current history any changes in longer-term trends in weather are captured.

Figures 7 & 8 below show the annual actual and weather-normal HDD and CDD used in the analysis in this report for MECO. Actual HDD and CDD are the actual degree days by billing months for each year and normal HDD and CDD are the ten-year average degree days by billing months from 2012 to 2021.

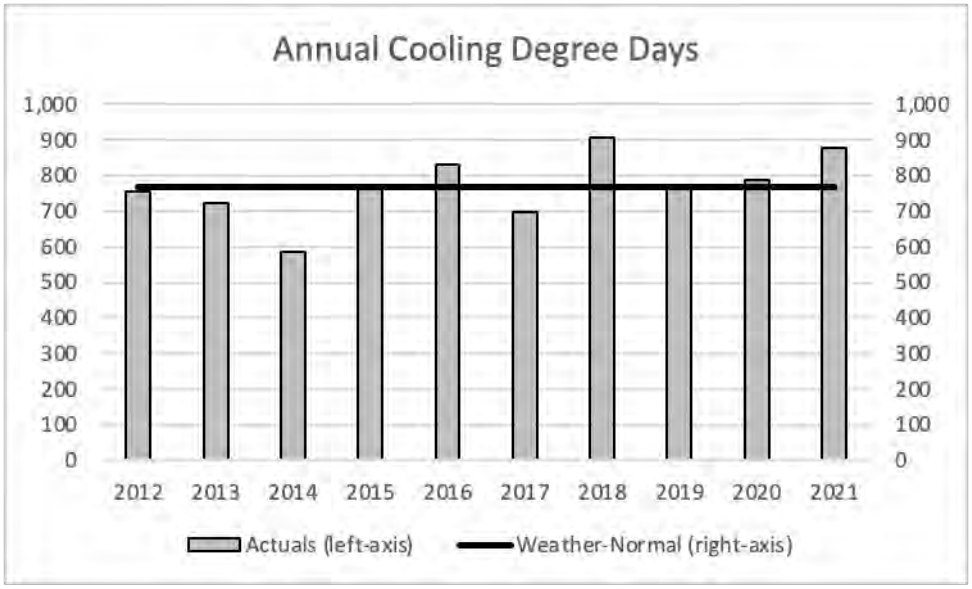

Figure 7: MECO annual cooling degree days

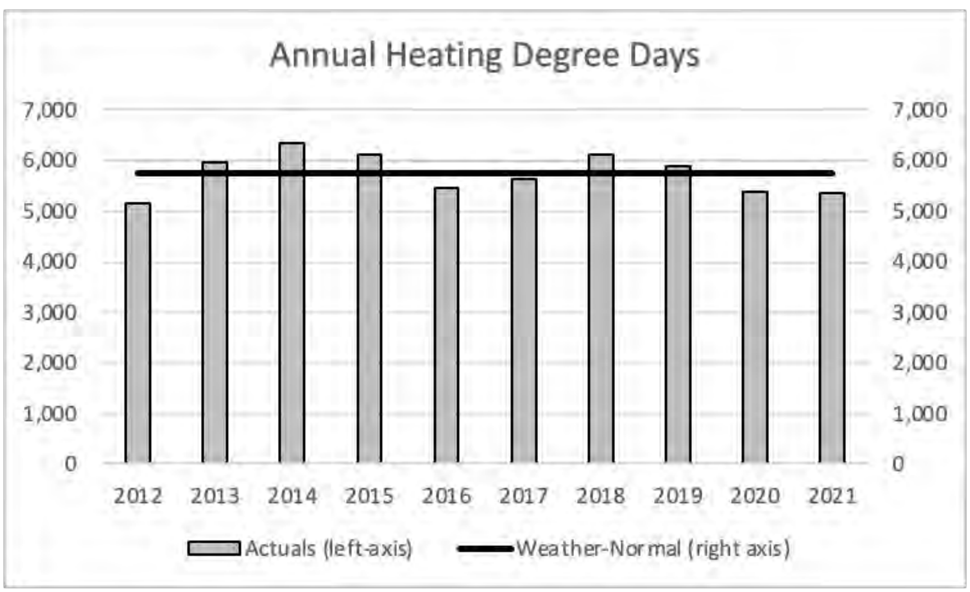

Figure 8: MECO Annual Heating Degree Days

Figure 9 shows the cyclical nature of the weather normalized cooling and heating degree days. The forecasts are based on billing month (solid lines). For comparative purposes, calendar month billing days are also shown. In general, the billing month degree-days have a lag compared to the calendar month degree-days. This is because the billing degree months have part current month and part prior month in them due the nature of bill reads. For example, the billing month of July would have degree days in both July and the prior month June, while calendar month July would have only July days.

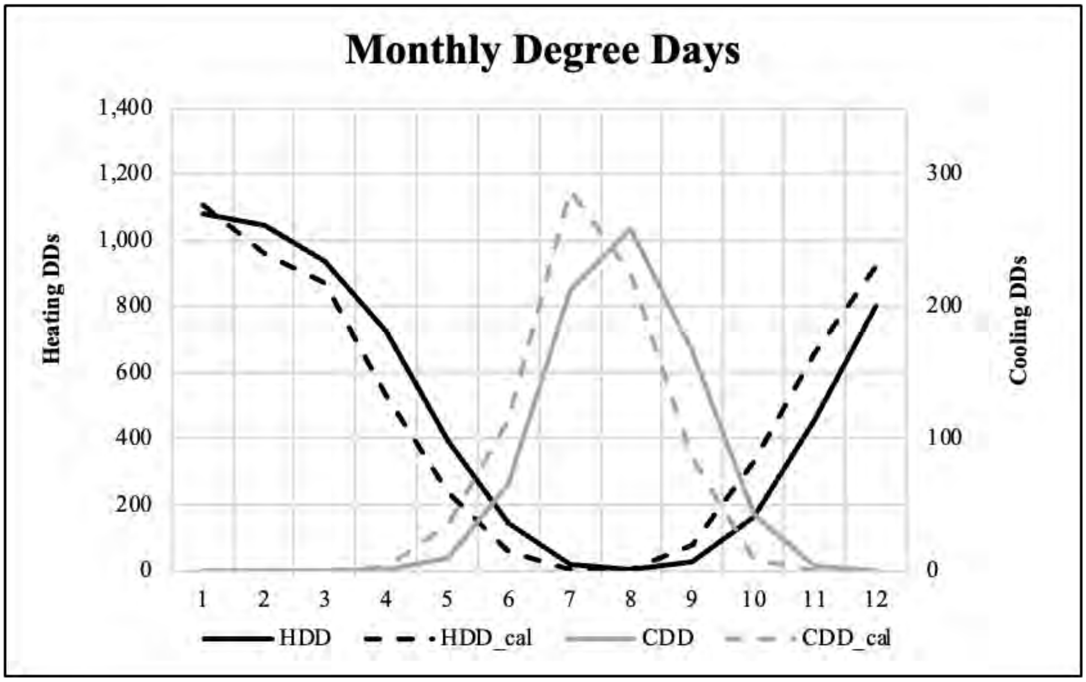

Figure 9: MECO Monthly Degree Days

Figures 10 and 11 show the annual heating and cooling degree days used in the analysis for Nantucket.

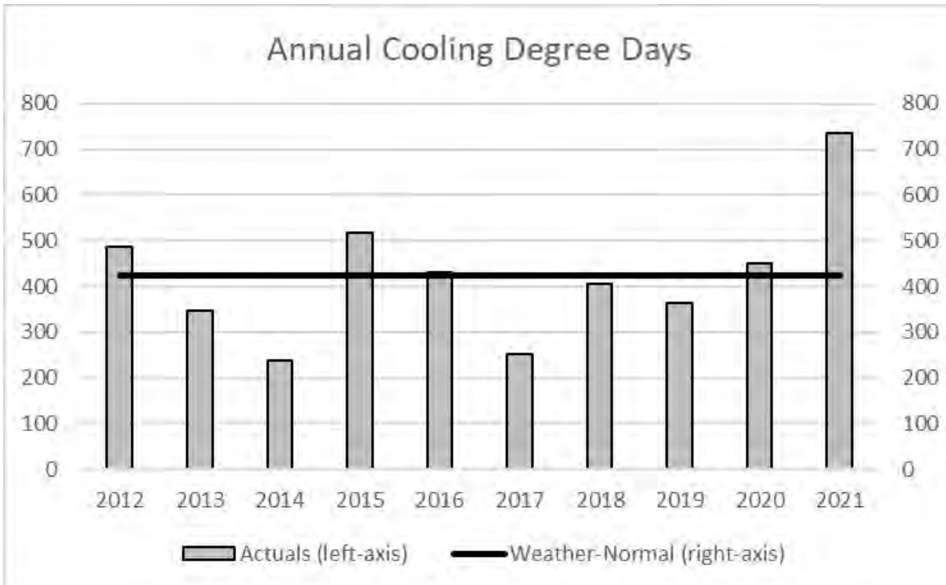

Figure 10: Nantucket Annual Cooling Degree Days

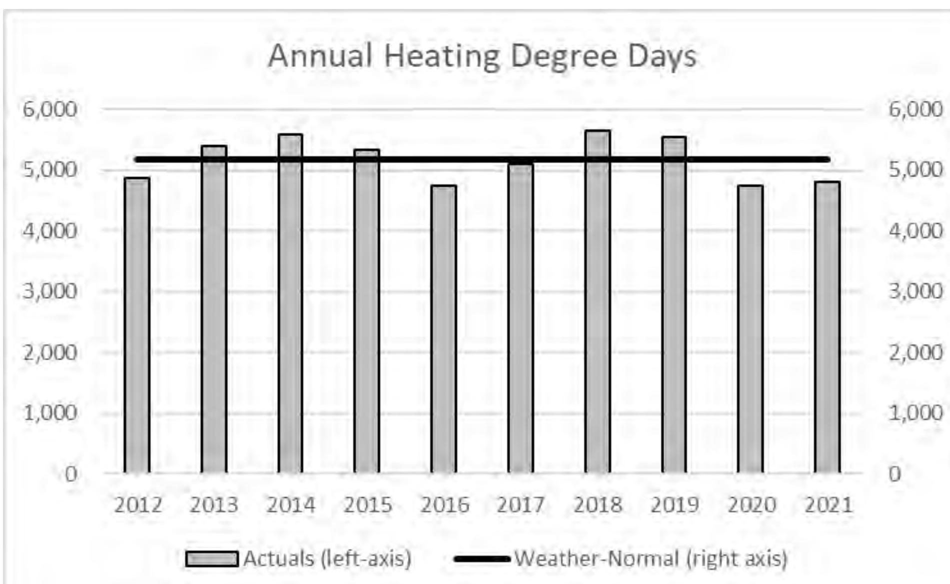

Figure 11: Nantucket Annual Heating Degree Days

Figure 12 shows the monthly weather normalized cooling and heating degree days for Nantucket.

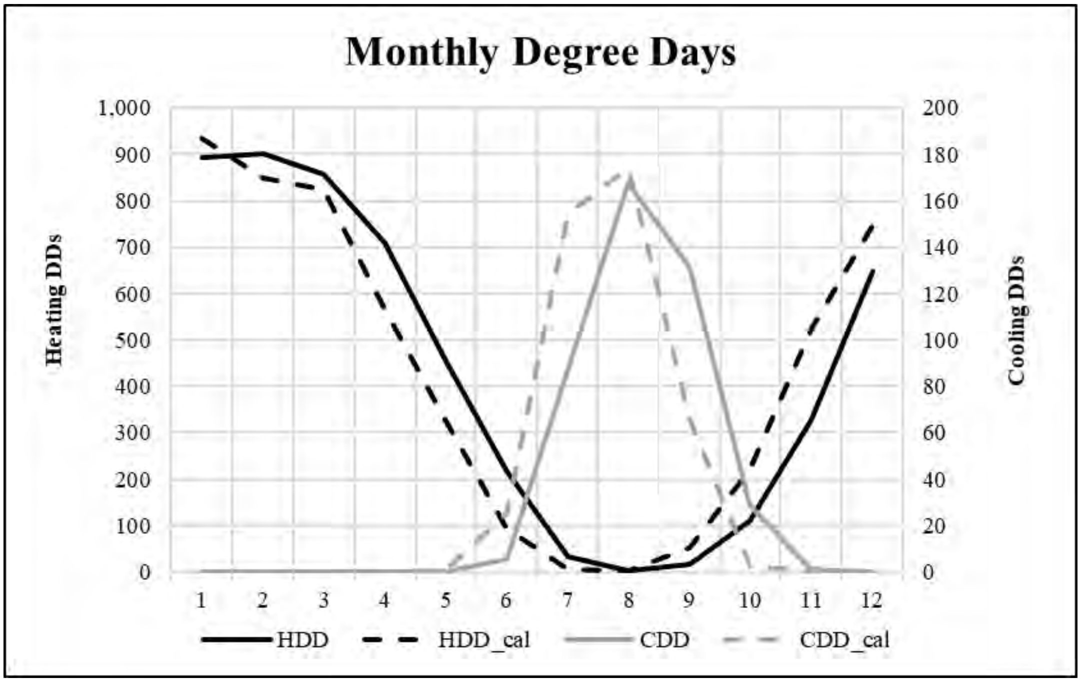

Figure 12: Nantucket Monthly Degree Days

1.4. Distributed Energy Resources (DERs)

In New England, there are a number of policies, programs, and technologies impact customer energy consumption. These include energy efficiency (EE), solar-photovoltaics (PV) and electric vehicles (EV) and electric heat pumps (EH). These collectively are termed distributed energy resources (DERs) because they impact the loads at the customer level, as opposed to at traditional, centralized power supplies. Demand Response (DR) and Energy Storage (ES) are accounted for in the peak forecast but do not materially impact energy consumption and are therefore not included here.

For MECO, Figure 13 shows the expected energy each year. The solid line shows the annual energy after the impacts of DERs and the dashed line shows the annual energy before those impacts. Figure 14 shows the impacts for the DERs each year. Figure 15 and 16 present the same for NANT.

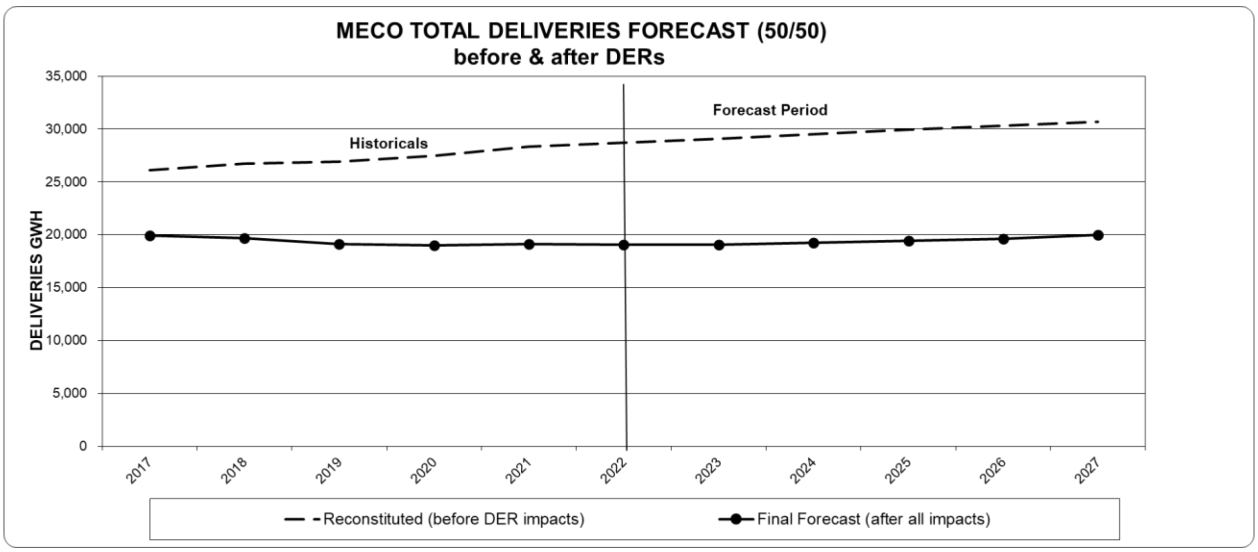

Figure 13: MECO Annual Loads before and after the impact of DERs

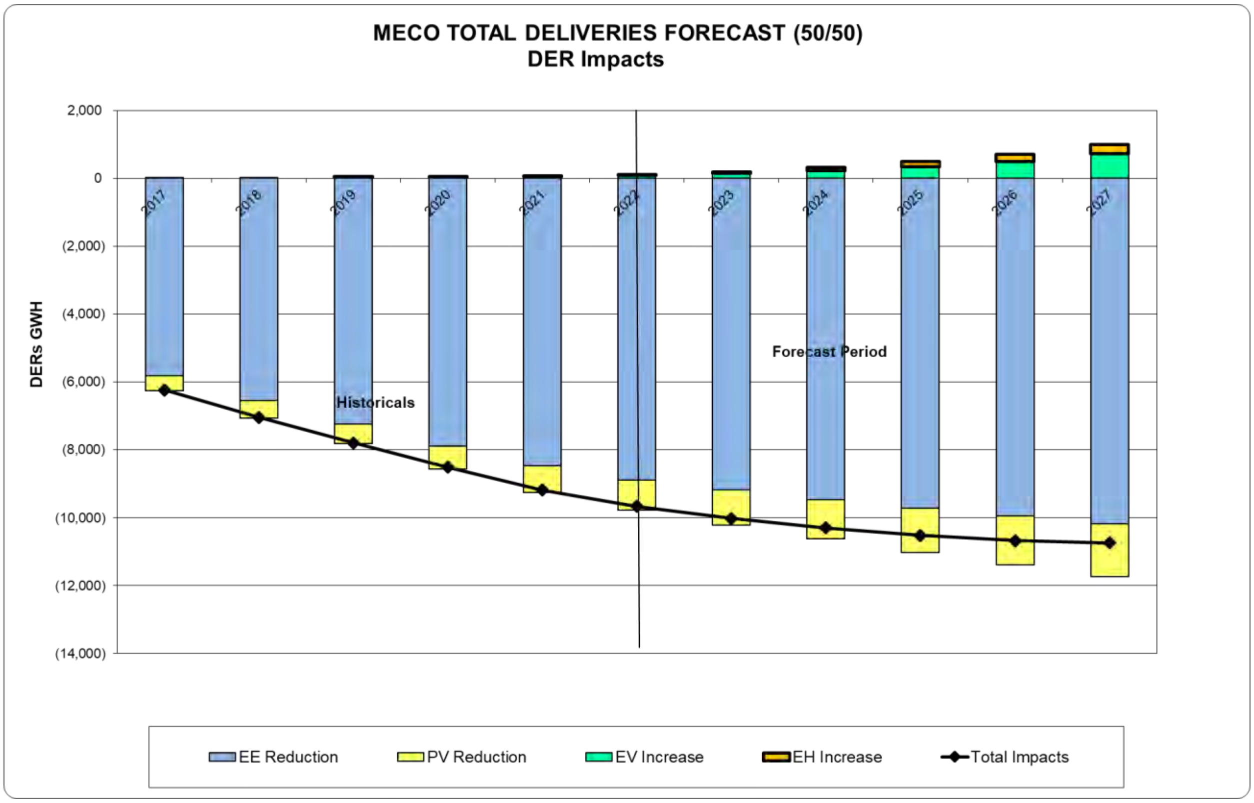

Figure 14: MECO Annual Impact of DERs

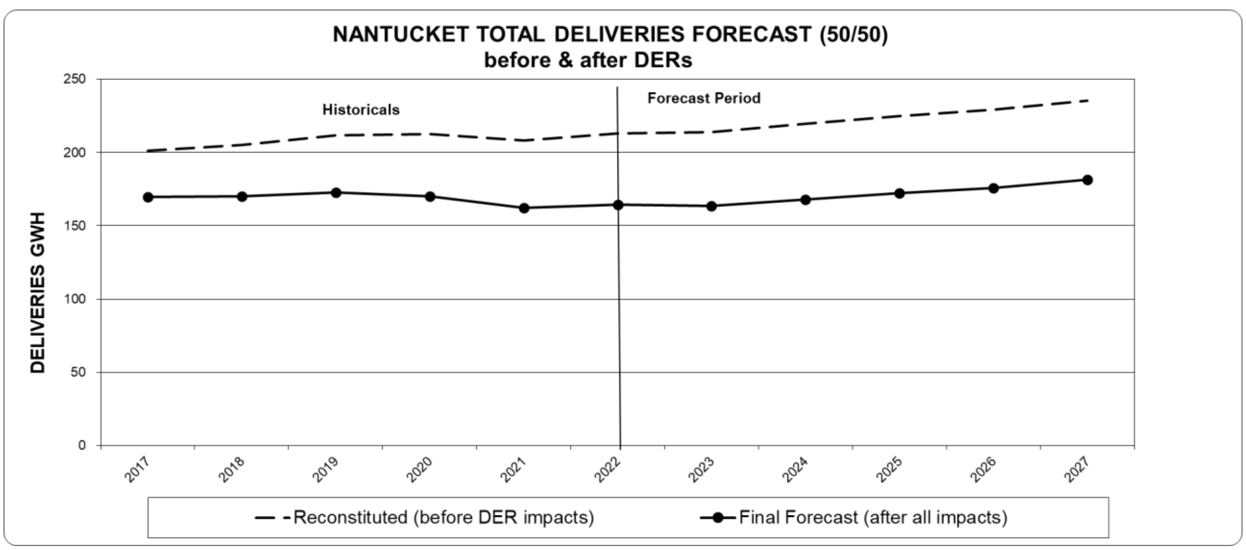

Figure 15: NANT Annual Loads before and after the impact of DERs

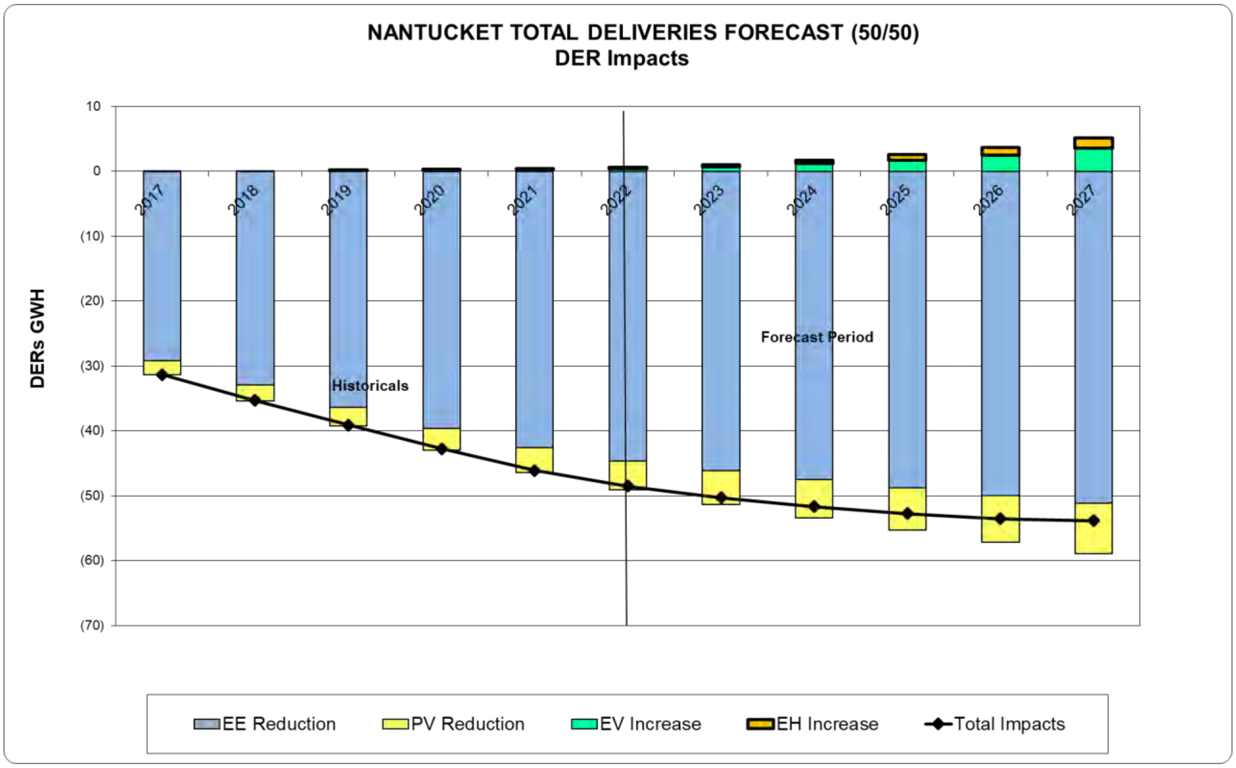

Figure 16: NANT Annual Impact of DERs

1.4.1 Energy Efficiency (EE)

National Grid has EE programs in its Massachusetts jurisdiction for many years and will continue to do so for the foreseeable future. In the short-term (one to three years), EE targets are based on Company annual plan from the Subject Matter Experts (SMEs) through 2024. Beyond 2024, the cumulative value of persistent EE savings is still expected to continue to grow but at a slower rate each year.

Figure 14 and 16 above shows the expected deduction to annual consumption for MECO and NANT by year. For MECO, as of 2022, it is estimated that these EE programs have reduced annual energy by 8,882 GWh, or 31.0% compared to the counterfactual with no EE programs. By 2027, it is expected that this reduction will grow to 10,177 GWh or 33.2% of what load would have been had these programs not been implemented. EE is expected to decrease future growth (before any DERs) from 1.4% per year to 0.7% per year on average over the next five years. Figure 17 presents the annual incremental (left) and cumulative (right) EE annual GWh.

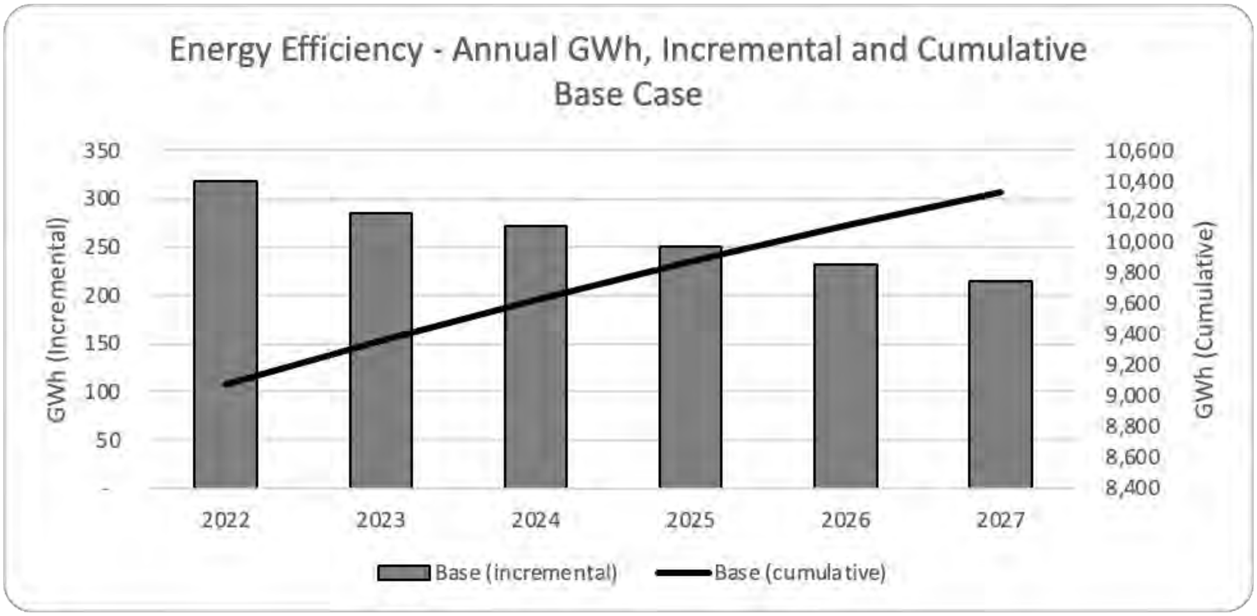

Figure 17: Massachusetts Incremental and Cumulative EE Forecasts (in service territory)

1.4.2 Solar-Photovoltaics (PV)

There has been a rapid increase in the adoption of PV throughout the state. The actual installed PV is tracked by the Company and used for the historical values. The near-term (2023-2027) predictions leveraged the information on the projects in the Company's queue and the insights from PV subject matter experts at the Company, and also assumes National Grid fills its share (i.e. 45%) of the State's existing solar standards of 3.2 GW by the end of the forecast horizon.

As of 2022, Company's Massachusetts service territory has about 1,745 MW[2] installed PV. This is expected to grow to about 2,607 MWs by 2027. Figure 18 shows the expected installed nameplate MW for PVs.

[2] AC nameplate capacity

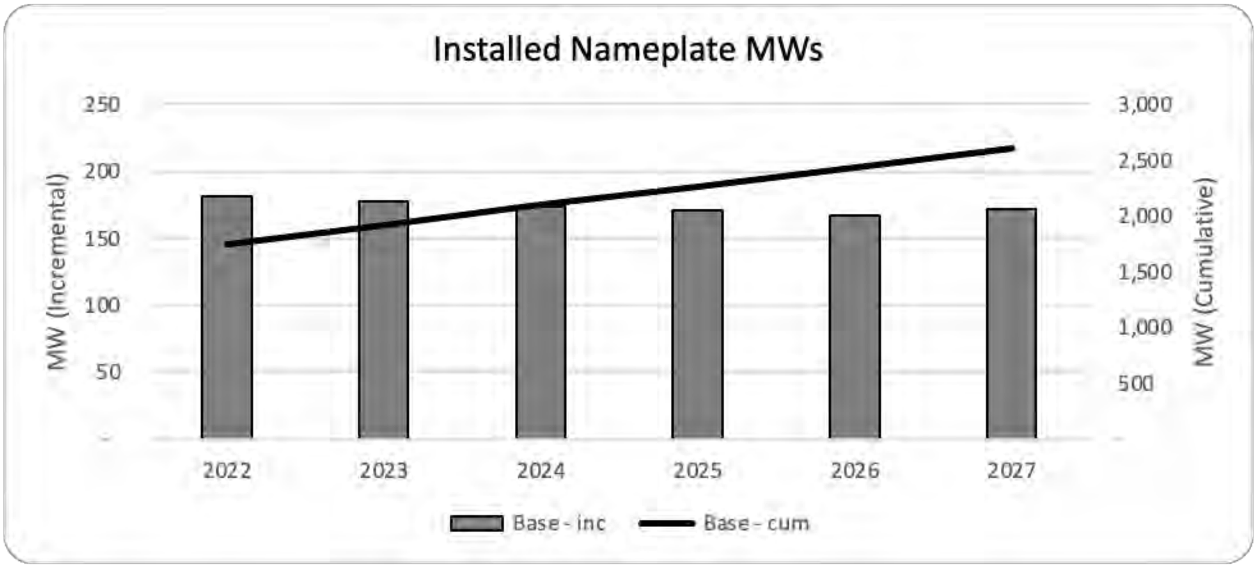

Figure 18: Massachusetts PV Nameplate in MW (in service territory)

Figure 14 and 16 above shows the expected deduction to annual consumption for MECO and NANT by year. As of 2022, it is estimated that this technology has already reduced MECO loads by 897 GWh, or 3.1% annually. By 2027 it is expected that these reductions may grow to 1,559 GWh, or 5.1% annually of what consumption would have been had this technology not been installed. Over the five-year planning horizon these reductions lower annual growth (before any DERs) from 1.4% to 1.0% per year.

1.4.3 Electric Vehicles (EV)

Electric vehicles increase energy consumption over time. Electric vehicles of interest are those that plug-in to the electric system and include "plug-in hybrid electric vehicles" (PHEVs) and "plug-in battery-only electric vehicles" (BEVs). These two types are those that have impacts on the electric network. Light-duty EVs, medium-duty EVs, heavy-duty EVs and electric buses are considered in this forecast.

The light-duty vehicle (LDV) base case is developed around California's Advanced Clean Car II (ACC-II) rules[3], which are expected to be adopted by Massachusetts. In the near-term, the zero-emission vehicle share of LDV sales is created based on the techno-economic potential and current market trends. In the medium-term (2026 -2030), the zero-emission vehicle sales projection aligns with the ACC-II case allowing flexibilities[4], reaching to 59.5% by 2030. The adoptions of medium-duty EV (MDEV), heavy- duty EV (HDEV) and E-buses is based on the California's Advanced Clean Trucks (ACT) rules through 2035 which have been adopted by the

[3] https://ww2.arb.ca.gov/rulemaking/2022/advanced-clean-cars-ii

[4] Flexibilities include provisions to transfer ZEV "sales values" across all states that have adopted the regulations (e.g., a manufacturer can overachieve in California and underachieve elsewhere), provisions to sell affordable EVs in environmental justice areas, and using historical ZEV sales credits to meet the annual ZEV sales targets. All of the flexibilities provided in the rules expire by or before 2031.

state. The sales shares for MDEV, HDEV, and E-buses are estimated to be about 63%, 40%, and 75% of MDV, HDV, and buses, respectively, by the end of 2035.

Figure 19 shows the estimated number of EVs in the Company's Massachusetts service territory. As of the end of 2022, it is estimated that about 32,200 EVs, including light-duty, medium-duty, heavy-duty and buses, will be on the roads in the Company's Massachusetts service territory, growing to about about 206,400 by 2027.

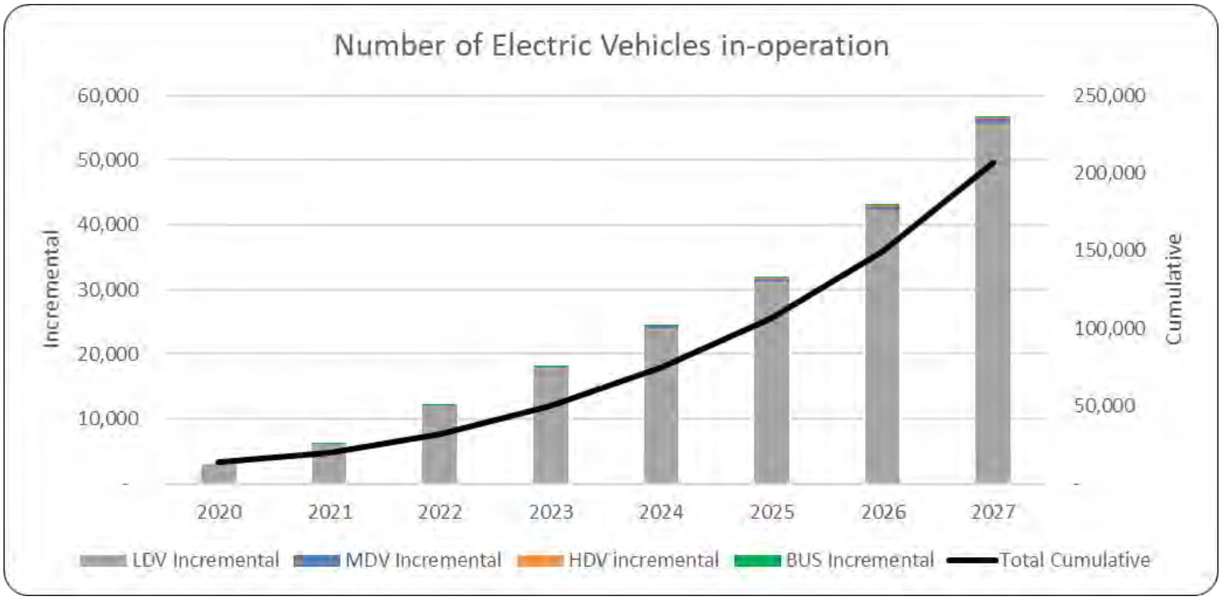

Figure 19: Massachusetts Number of Electric Vehicles (in service territory)

Figure 14 & 16 above shows the expected increase to annual consumption by year. Electric vehicles annual energy impacts are estimated for light-duty, medium-duty, heavy-duty, and electric buses separately. The annual energy impact of light-duty EVs is estimated to be 3,316 kWh per EV in year 2022 and gradually grow to 3,688 kWh per EV by 2027 in anticipating the increasing share of BEV types. For medium-duty EVs, heavy-duty EVs, and electric buses, the annual energy impacts are estimated to be 11,847 kWh per EV, 38,848 kWh per EV, and 100,839 kWh per EV, respectively. For MECO, as of 2022, it is estimated that this technology may have already added 89 GWh, or 0.3% to energy consumption. By 2027 it is expected that the impact from this techonoloy may grow to 722 GWh, or 2.4% of what consumption would have been had this technology not been installed. Over the five-year planning horizon these raise annual growth (before any DERs) from 1.4% to 1.8% per year.

1.4.4 Electric Heat Pumps (EH)

The base case is based on the Company's heat pump targets until 2024. Post 2024, the Company assumes it's pro rata share of CECP phased pathway's target in 2050 will be met[5]. Figure 20 shows the annual number of full and partial electric heat pumps assumed in the Company's Massachusetts service territory[6]. A full heat pump is defined as a unit will serve the all the heating and cooling in the home or building. A partial heat pump is defined as a unit that will supplement existing heating system, as well as cool the home or building during the summer season.

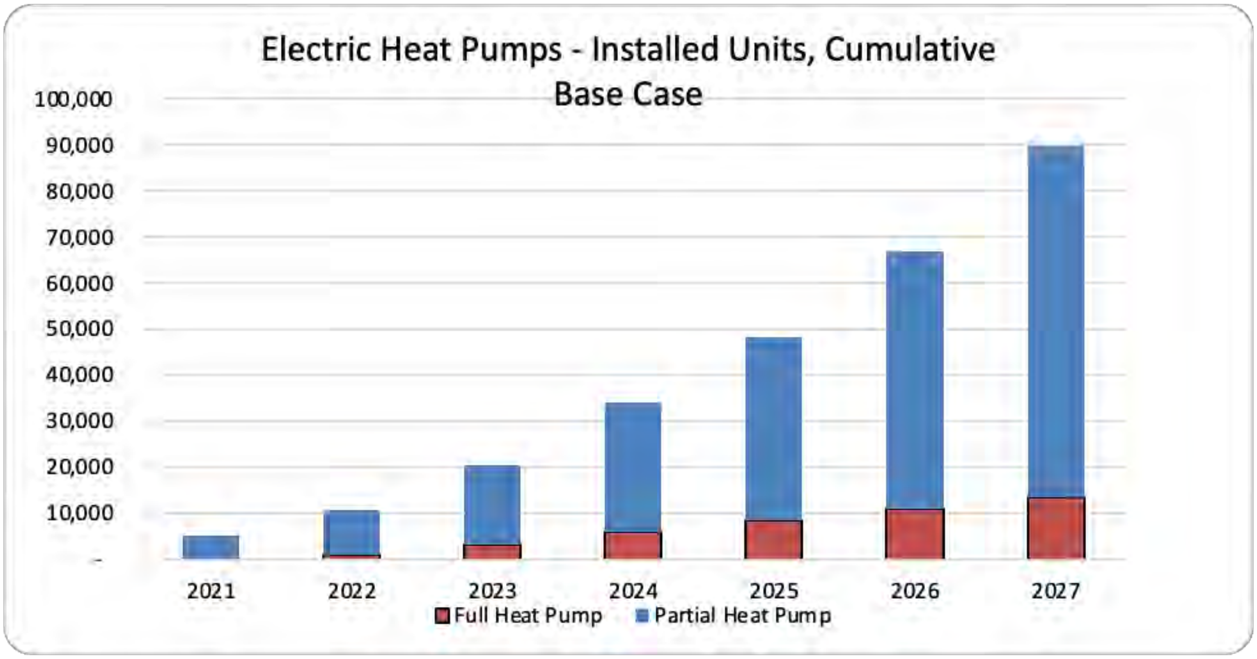

Figure 20: Number of electric heat pumps

Figure 14 and 16 above shows the expected increase to annual consumption by year. As of 2022, it is estimated that this technology will add MECO's annual energy by 25 GWh, or 0.1%. By 2027 it is expected that this may grow to 271 GWh, or 1.0%. Over the five-year planning horizon these technology raises annual growth (before any DERs) from 1.4% to 1.5% per year.

Appendices A1 and A2 show additional details for the DERs.

The DER projections included in this forecast are based on current trends, approved programs, and existing state policy targets. It is considered the most probable scenario at this time and is not intended to be inclusive of other activities including expanded renewables due to climate and

[5] Massachusetts Clean Energy and Climate Plan for 2025 and 2030, June 30, 2022
[6] The number is the total adoption but the legacy electric heat replacement (about 16%, based on American Community Survey) is excluded in the forecasting.

other regional discussions. The Company is actively monitoring these processes and will incorporate, as appropriate, new policies as they become more likely.

1.5 Economic Scenarios

The discussion thus far has been confined to the base case economic scenario. The Company also developed parallel forecasts for both a higher and a lower economic scenario. The higher than base (or upside or Moody's S0) scenario2 is designed so that there is a 4% probability that the economy will perform better than in this scenario. It is based on the assumptions that Russian invasion of Ukraine resolves much faster than anticipated thereby the worries surrounding the global oil supply recede quickly and the supply-chain issues also diminish much more quickly reducing the shortage of affected goods and commodities. As a result, the inflation decelerates to Fed's target sooner than expected. New cases, hospitalizations, and deaths from COVID-19 recede faster than in the baseline. The economy returns to full employment in the fourth quarter of 2022 below the level assumed in the baseline with the real GDP higher than the baseline in 2023 and 2024. The lower than base (or downside or Moody's S4) scenario is designed so that there is a 96% probability that the economy will perform better than in this scenario. It assumes Russian invasion of Ukraine and supply-chain issue worsens causing more shortage of global oil supply and goods and commodities than assumed in the baseline putting upward pressure on inflation. New cases, hospitalizations, and deaths from COVID-19 rise significantly thus slowing the economic activity. It is also assumed that resurgence in COVID-19 aggravates the supply-chain problem further thereby raising the inflation. The economy falls into deep recession in the fourth quarter of 2022 and the unemployment rate continues to worsen.

Massachusetts Electric Company

Figure 21 shows the forecasts from using the base, high and low economic scenarios for MECO.

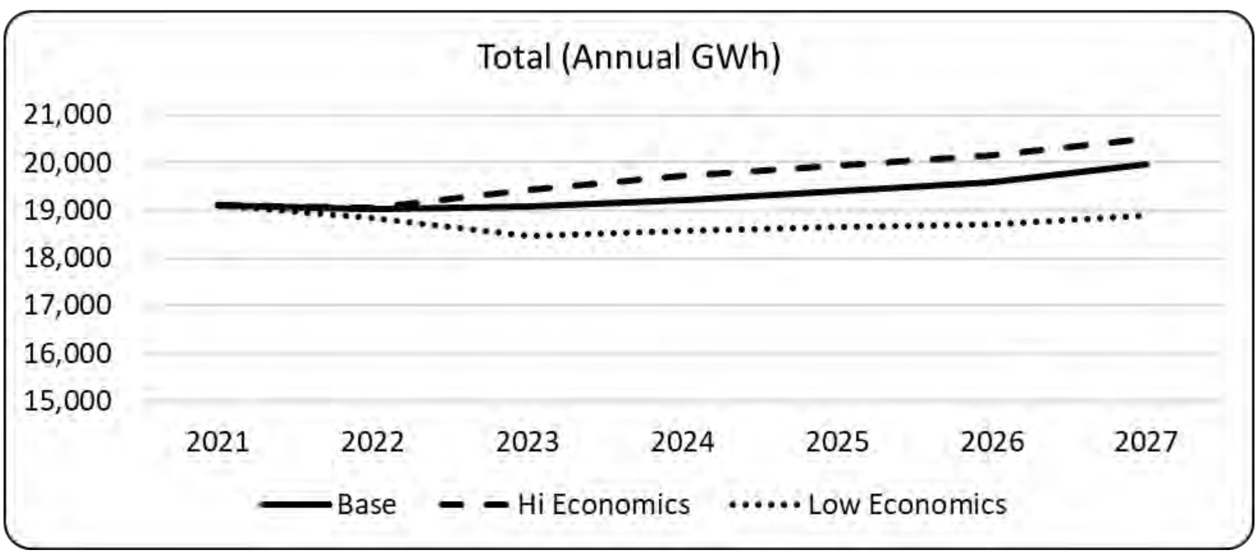

Figure 21: MECO Comparison of Forecasts using Base, High and Low Economic Scenarios

Table 3 shows a comparison of the values for the high and low economic scenarios versus the base case.

Table 3: Comparison of Forecasts from Base, High and Low Economic Scenarios

Calendar	Economics (base)	Economic (low)			Economic (high)		
Year	Forecast (GWh)	Forecast (GWh)	Delta (GWh)	Delta (%)	Forecast (GWh)	Delta (GWh)	Delta (%)
2022	19,022	18,852	(170)	-0.9%	19,055	34	0.2%
2023	19,080	18,453	(628)	-3.3%	19,419	338	1.8%
2024	19,218	18,559	(659)	-3.4%	19,715	496	2.6%
2025	19,415	18,659	(755)	-3.9%	19,954	539	2.8%
2026	19,602	18,702	(900)	-4.6%	20,150	548	2.8%
2027	19,957	18,900	(1,057)	-5.3%	20,500	543	2.7%

Both the forecast using Moody's baseline and the one using the high economic scenario expect growth every year through the planning horizon, with the high scenario predicting 2.7% higher by the end of the five-year planning horizon. The forecast from using the low economic scenario is considerably lower than the forecast using the baseline. It predict small decline in residential sector for later years in the forecast horizon and immediate decline in the commercial and industrial sectors. In the low economic scenario, for the next five years, the residential sector is expected to grow by 1.3% per year comparing to 1.8% using Moody's baseline scenario, the commercial sector is expected to decline by 0.7% per year comparing to a 0.8% growth per year using Moody's baseline scenario, and the industrial sector is expected to decline by 1.0% per year comparing to a smaller decline of 0.6% per year using Moody's baseline scenario.

Nantucket Electric Company

Figure 22 shows the forecasts from using the base, high and low economic scenarios for NANT.

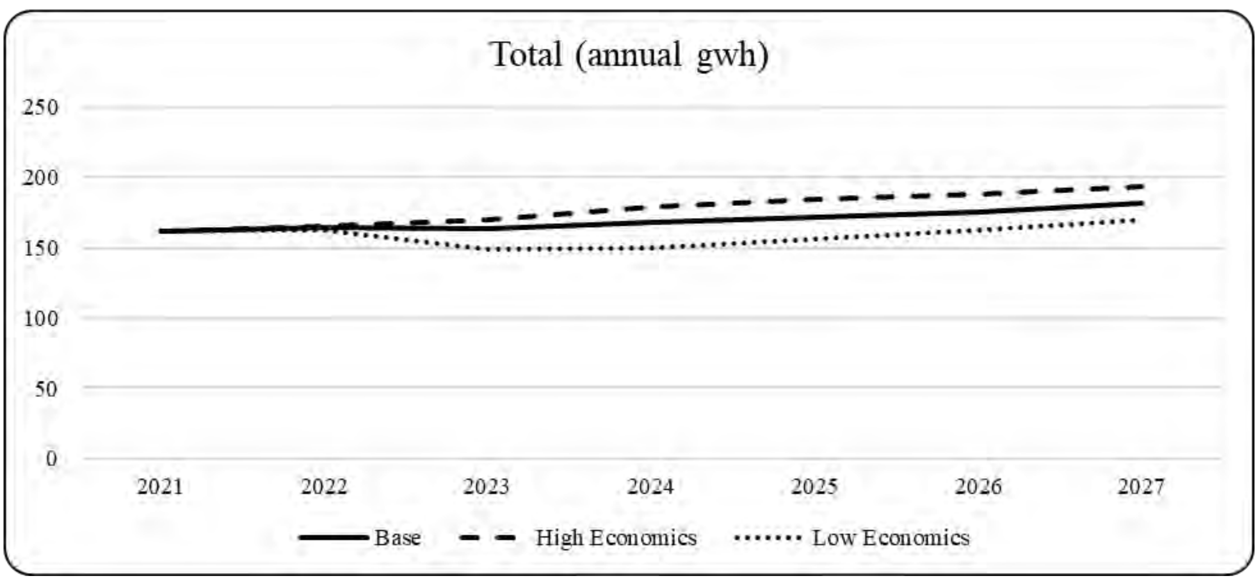

Figure 22: NANT Comparison of Forecasts using Base, High and Low Economic Scenarios

Table 4 shows a comparison of the values for the high and low economic scenarios versus the base case.

Table 4: Comparison of Forecasts from Base, High and Low Economic Scenarios

Calendar	Economic (Base)	Economic (low)			Economic (high)		
Year	Forecast (GWh)	Forecast (GWh)	Delta (GWh)	Delta (%)	Forecast (GWh)	Delta (GWh)	Delta (%)
2022	164.5	163.0	(1.5)	-0.9%	165.3	0.8	0.5%
2023	163.7	148.9	(14.8)	-9.0%	170.2	6.5	4.0%
2024	168.0	149.5	(18.5)	-11.0%	178.6	10.6	6.3%
2025	172.1	156.1	(16.0)	-9.3%	184.1	11.9	6.9%
2026	175.7	162.6	(13.2)	-7.5%	187.8	12.1	6.9%
2027	181.5	170.2	(11.3)	-6.2%	193.9	12.5	6.9%

1.6 Comparison to Previous Year's Forecast

Massachusetts Electric Company

Figure 23 shows a comparison of this year's forecast to last year's (vintage Fall 2021). It presents this comparison in two ways. The first in terms the "Gross" (or before the impacts of DERs) and the second is "Net" (after the impacts of DERs).

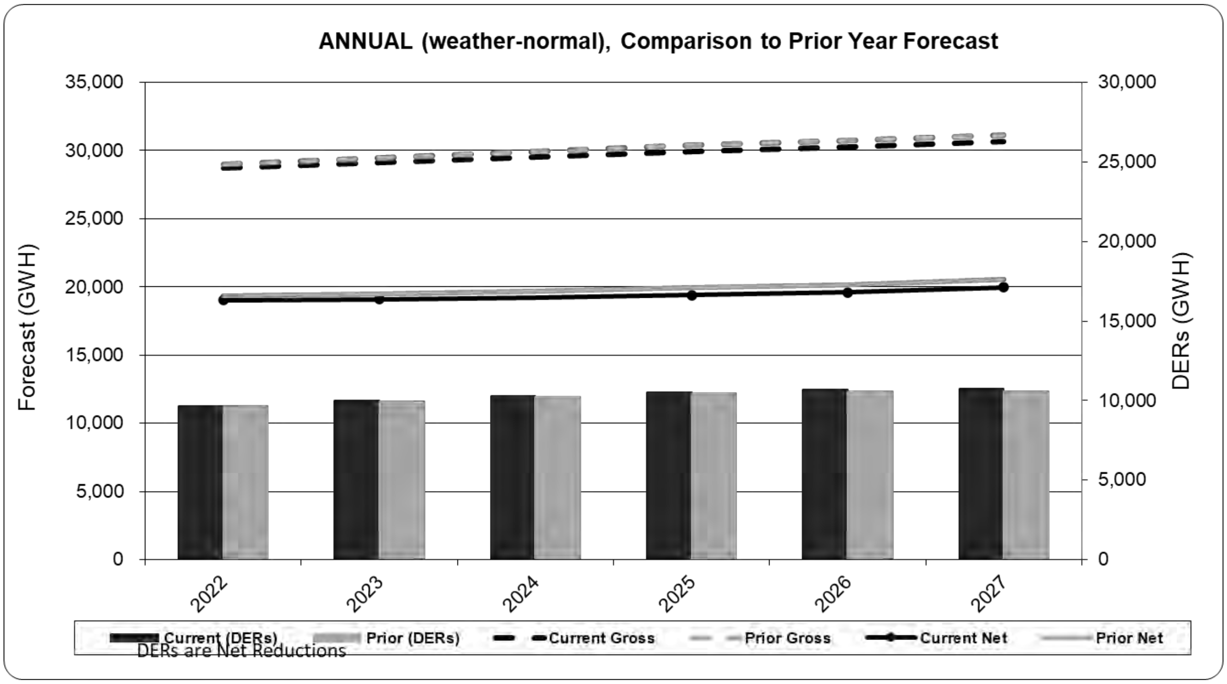

Figure 23: MECO Comparison of Forecasts and DERs, Current 2022 vs. Prior 2021 Vintages

Table 5 contains the numbers supporting Figure 23.

Table 5: MECO Comparison of Forecasts and DERs, Current 2022 vs. Prior 2021 Vintages

MECO ANNUAL GWh (weather-normal)										
	Current Forecast (Fall 2022)					Prior Forecast (Fall 2021)				
CALENDAR	Gross		Net		DER	Gross		Net		DER
YEAR	(GWh)	(% Grwth)	(GWh)	(% Grwth)	(GWh)	(GWh)	(% Grwth)	(GWh)	(% Grwth)	(GWh)
2022	28,688	1.4%	19,022	-0.5%	9,666	28,995	2.1%	19,355	0.7%	9,640
2023	29,097	1.4%	19,080	0.3%	10,016	29,472	1.6%	19,514	0.8%	9,958
2024	29,519	1.5%	19,218	0.7%	10,301	29,935	1.6%	19,695	0.9%	10,240
2025	29,936	1.4%	19,415	1.0%	10,522	30,370	1.5%	19,931	1.2%	10,439
2026	30,277	1.1%	19,602	1.0%	10,674	30,707	1.1%	20,167	1.2%	10,540
2027	30,698	1.4%	19,957	1.8%	10,742	31,130	1.4%	20,581	2.1%	10,549

As shown in the figure and the table, the 2022 release has a similar outlook as the 2021 release on the gross energy forecasts and DER impacts through the five-year forecast horizon.

Nantucket Electric Company

Figure 24 shows a comparison of this year's forecast to last year's (vintage Fall 2021). It presents this comparison in two ways. The first in terms the "Gross" (or before the impacts of DERs) and the second is "Net" (after the impacts of DERs).

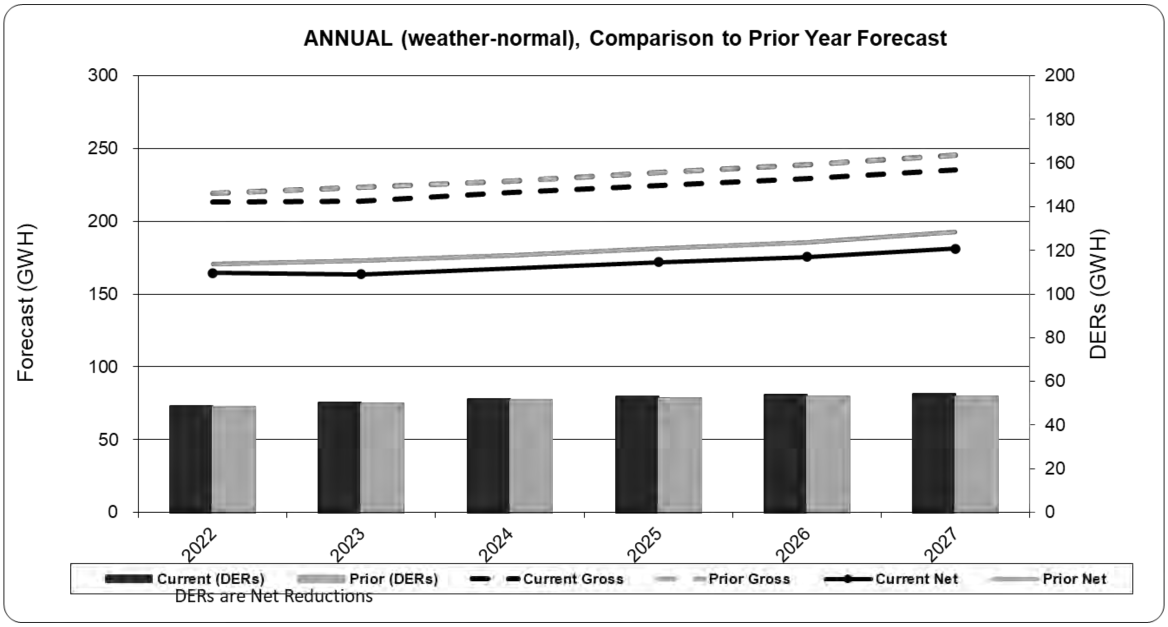

Figure 24: NANT Comparison of Forecasts and DERs, Current 2022 vs. Prior 2021 Vintages

Table 6 contains the numbers supporting Figure 24.

Table 6: NANT Comparison of Forecasts and DERs, Current 2022 vs. Prior 2021 Vintages

As shown in the figure and the table, the 2022 release has a similar outlook on the gross energy forecasts and DER impacts through the forecast horizon.

2. Massachusetts Electric Company

2.1. Forecasted Fiscal Year Deliveries by Revenue Class

ANNUAL GWh (*and percent growth*) FISCAL YEAR (Historicals & Projections: Weather-Normal) by Revenue Class
After Energy Efficiency, Solar and Electric Vehicle Impacts

FISCAL YEAR	RESIDENTIAL Non-Heating		Elec Heating		RESIDENTIAL Total		COMMERCIAL		INDUSTRIAL		StreetLighting & Other		M		TOTAL	
2008	7,708.3		945.2		8,653.5		9,443.7		3,766.2		110.2		10.3		21,973.5	
2009	7,649.1	-0.8%	919.5	-2.7%	8,568.6	-1.0%	9,439.6	0.0%	3,703.1	-1.7%	110.2	0.0%	9.9	-4.2%	21,821.5	-0.7%
2010	7,737.6	1.2%	906.9	-1.4%	8,644.5	0.9%	9,257.1	-1.9%	3,394.8	-8.3%	109.0	-1.1%	9.5	-3.6%	21,405.4	-1.9%
2011	7,831.8	1.2%	903.4	-0.4%	8,735.2	1.0%	9,177.5	-0.9%	3,362.5	-1.0%	108.7	-0.2%	9.7	2.5%	21,384.0	-0.1%
2012	7,874.2	0.5%	895.5	-0.9%	8,769.7	0.4%	9,221.0	0.5%	3,268.8	-2.8%	108.4	-0.3%	9.0	-8.0%	21,368.0	-0.1%
2013	7,991.1	1.5%	895.4	0.0%	8,886.4	1.3%	9,218.6	0.0%	3,203.3	-2.0%	109.4	0.9%	9.3	3.5%	21,417.7	0.2%
2014	8,014.6	0.3%	898.6	0.4%	8,913.2	0.3%	9,141.9	-0.8%	3,140.8	-2.0%	106.6	-2.6%	9.6	3.3%	21,302.5	-0.5%
2015	7,737.7	-3.5%	872.1	-2.9%	8,609.8	-3.4%	9,095.6	-0.5%	3,145.9	0.2%	110.4	3.6%	8.6	-10.5%	20,961.8	-1.6%
2016	7,512.6	-2.9%	824.1	-5.5%	8,336.7	-3.2%	9,134.9	0.4%	3,080.5	-2.1%	107.8	-2.4%	6.7	-22.0%	20,659.8	-1.4%
2017	7,337.1	-2.3%	796.5	-3.3%	8,133.7	-2.4%	8,924.3	-2.3%	2,853.1	-7.4%	103.5	-4.0%	7.1	6.2%	20,014.5	-3.1%
2018	7,320.9	-0.2%	801.9	0.7%	8,122.8	-0.1%	8,896.3	-0.3%	2,776.6	-2.7%	99.6	-3.8%	6.4	-9.5%	19,895.2	-0.6%
2019	7,277.8	-0.6%	782.7	-2.4%	8,060.4	-0.8%	8,815.3	-0.9%	2,623.1	-5.5%	80.5	-19.2%	6.9	7.1%	19,579.3	-1.6%
2020	7,043.8	-3.2%	763.4	-2.5%	7,807.3	-3.1%	8,671.5	-1.6%	2,511.5	-4.3%	75.4	-6.3%	6.3	-9.0%	19,065.7	-2.6%
2021	7,686.1	9.1%	774.2	1.4%	8,460.3	8.4%	8,039.9	-7.3%	2,421.3	-3.6%	59.1	-21.6%	6.1	-2.0%	18,980.6	-0.4%
2022	7,380.0	-4.0%	763.3	-1.4%	8,143.3	-3.7%	8,330.9	3.6%	2,433.9	0.5%	56.0	-5.2%	6.0	-1.9%	18,964.1	-0.1%
2023	7,514.9	1.8%	739.6	-3.1%	8,254.4	1.4%	8,327.0	0.0%	2,458.1	1.0%	60.5	8.0%	6.0	-1.0%	19,100.1	0.7%
2024	7,511.8	0.0%	765.2	3.5%	8,277.1	0.3%	8,346.2	0.2%	2,427.5	-1.2%	64.2	6.1%	6.0	0.0%	19,114.9	0.1%
2025	7,649.2	1.8%	780.5	2.0%	8,429.7	1.8%	8,418.8	0.9%	2,401.3	-1.1%	63.6	-0.9%	6.0	0.0%	19,313.4	1.0%
2026	7,781.5	1.7%	796.5	2.0%	8,578.0	1.8%	8,483.6	0.8%	2,359.2	-1.8%	63.0	-0.9%	6.0	0.0%	19,483.8	0.9%
2027	7,951.9	2.2%	817.8	2.7%	8,769.7	2.2%	8,554.8	0.8%	2,312.2	-2.0%	62.4	-0.9%	6.0	0.0%	19,699.1	1.1%
2028	8,207.0	3.2%	847.2	3.6%	9,054.2	3.2%	8,666.8	1.3%	2,277.9	-1.5%	61.9	-0.9%	6.0	0.0%	20,060.8	1.8%
Annual Growth Rates:																
prior 15 years		-0.2%		-1.6%		-0.3%		-0.8%		-2.8%		-3.9%		-3.6%		-0.9%
prior 10 years		-0.6%		-1.9%		-0.7%		-1.0%		-2.6%		-5.8%		-4.3%		-1.1%
prior 5 years		0.5%		-1.6%		0.3%		-1.3%		-2.4%		-9.5%		-1.5%		-0.8%
BASE YEAR:		**2023**														
next 5 years		1.8%		2.8%		1.9%		0.8%		-1.5%		0.5%		0.0%		1.0%

2.2. Forecasted Fiscal Year Customer Counts by Revenue Class

ANNUAL CUSTOMER COUNTS, FISCAL YEAR by Revenue Class														
CALENDAR YEAR	RESIDENTIAL Non-Heating		Elec Heating		RESIDENTIAL Total		COMMERCIAL		INDUSTRIAL		StreetLighting & Other		TOTAL	
2008	1,019,127		82,817		1,101,944		155,931		4,874		1,707		1,264,466	
2009	1,021,187	0.2%	82,613	-0.2%	1,103,800	0.2%	155,644	-0.2%	4,710	-3.4%	1,982	16.1%	1,266,135	0.1%
2010	1,029,838	0.8%	82,629	0.0%	1,112,467	0.8%	157,054	0.9%	4,667	-0.9%	2,405	21.3%	1,276,594	0.8%
2011	1,037,953	0.8%	82,814	0.2%	1,120,767	0.7%	158,282	0.8%	4,609	-1.2%	2,768	15.1%	1,286,428	0.8%
2012	1,041,268	0.3%	82,671	-0.2%	1,123,939	0.3%	159,381	0.7%	4,548	-1.3%	3,081	11.3%	1,290,950	0.4%
2013	1,045,146	0.4%	82,524	-0.2%	1,127,671	0.3%	160,180	0.5%	4,476	-1.6%	3,482	13.0%	1,295,811	0.4%
2014	1,048,667	0.3%	82,465	-0.1%	1,131,132	0.3%	160,839	0.4%	4,399	-1.7%	3,675	5.5%	1,300,042	0.3%
2015	1,053,420	0.5%	82,392	-0.1%	1,135,812	0.4%	161,858	0.6%	4,364	-0.8%	3,717	1.1%	1,305,757	0.4%
2016	1,062,394	0.9%	82,459	0.1%	1,144,853	0.8%	162,748	0.5%	4,312	-1.2%	3,582	-3.6%	1,315,504	0.7%
2017	1,057,399	-0.5%	81,653	-1.0%	1,139,052	-0.5%	162,694	0.0%	4,223	-2.1%	3,489	-2.6%	1,309,464	-0.5%
2018	1,066,349	0.8%	81,682	0.0%	1,148,032	0.8%	164,918	1.4%	4,157	-1.6%	3,476	-0.4%	1,320,582	0.8%
2019	1,072,691	0.6%	81,223	-0.6%	1,153,913	0.5%	165,915	0.6%	4,081	-1.8%	3,453	-0.7%	1,327,363	0.5%
2020	1,082,912	1.0%	81,247	0.0%	1,164,159	0.9%	167,092	0.7%	4,027	-1.3%	3,416	-1.1%	1,338,695	0.9%
2021	1,090,061	0.7%	80,206	-1.3%	1,170,267	0.5%	166,150	-0.6%	3,929	-2.4%	3,370	-1.3%	1,343,718	0.4%
2022	1,105,751	1.4%	80,214	0.0%	1,185,965	1.3%	165,673	-0.3%	3,831	-2.5%	3,340	-0.9%	1,358,810	1.1%
2023	1,107,975	0.2%	80,657	0.6%	1,188,632	0.2%	166,342	0.4%	3,864	0.9%	3,348	0.2%	1,362,185	0.2%
2024	1,105,217	-0.2%	80,747	0.1%	1,185,964	-0.2%	167,543	0.7%	4,112	6.4%	3,330	-0.5%	1,360,949	-0.1%
2025	1,108,753	0.3%	80,627	-0.1%	1,189,380	0.3%	168,061	0.3%	4,215	2.5%	3,304	-0.8%	1,364,960	0.3%
2026	1,112,254	0.3%	80,510	-0.1%	1,192,764	0.3%	168,568	0.3%	4,240	0.6%	3,276	-0.9%	1,368,848	0.3%
2027	1,115,010	0.2%	80,418	-0.1%	1,195,428	0.2%	168,967	0.2%	4,232	-0.2%	3,247	-0.9%	1,371,875	0.2%
2028	1,117,274	0.2%	80,342	-0.1%	1,197,616	0.2%	169,296	0.2%	4,214	-0.4%	3,109	-4.2%	1,374,346	0.2%
Annual Growth Rates:														
prior 15 years		0.6%		-0.2%		0.5%		0.4%		-1.5%		4.6%		0.5%
prior 10 years		0.6%		-0.2%		0.5%		0.4%		-1.5%		-0.4%		0.5%
prior 5 years		0.8%		-0.3%		0.7%		0.2%		-1.5%		-0.7%		0.6%
BASE YEAR:		**2023**												
next 5 years		0.2%		-0.1%		0.2%		0.4%		1.7%		-1.5%		0.2%

2.3. Forecasted Fiscal Year Deliveries by Rate Class

ANNUAL GWh (*and percent growth*) FISCAL YEAR (Historicals & Projections: Weather-Normal) by Rate Code
After Energy Efficiency, Solar and Electric Vehicle Impacts

FISCAL YEAR	RI		R2		R4		G1		G2		G3		SL		TOTAL	
2008	8,019.4		659.9		14.4		2,221.2		2,893.2		8,027.6		137.8		21,973.5	
2009	7,877.6	-1.8%	716.5	8.6%	13.8	-4.3%	2,202.2	-0.9%	2,876.5	-0.6%	7,997.9	-0.4%	137.0	-0.6%	21,821.5	-0.7%
2010	7,820.2	-0.7%	849.6	18.6%	13.4	-3.1%	2,128.9	-3.3%	2,792.5	-2.9%	7,666.1	-4.1%	134.7	-1.7%	21,405.4	-1.9%
2011	7,867.4	0.6%	895.3	5.4%	12.7	-5.0%	2,151.1	1.0%	2,784.1	-0.3%	7,541.7	-1.6%	131.7	-2.3%	21,384.0	-0.1%
2012	7,813.4	-0.7%	983.1	9.8%	12.4	-2.2%	2,143.1	-0.4%	2,801.3	0.6%	7,483.3	-0.8%	131.4	-0.2%	21,368.0	-0.1%
2013	7,836.0	0.3%	1,075.8	9.4%	11.9	-3.9%	2,176.5	1.6%	2,801.7	0.0%	7,384.6	-1.3%	131.1	-0.3%	21,417.7	0.2%
2014	7,800.6	-0.5%	1,137.4	5.7%	11.9	-0.6%	2,167.2	-0.4%	2,794.9	-0.2%	7,263.9	-1.6%	126.7	-3.3%	21,302.5	-0.5%
2015	7,474.4	-4.2%	1,160.5	2.0%	11.4	-4.0%	2,156.4	-0.5%	2,806.1	0.4%	7,222.2	-0.6%	130.9	3.3%	20,961.8	-1.6%
2016	7,169.6	-4.1%	1,191.7	2.7%	10.3	-9.5%	2,144.3	-0.6%	2,800.2	-0.2%	7,214.2	-0.1%	129.6	-1.0%	20,659.8	-1.4%
2017	7,114.8	-0.8%	1,042.4	-12.5%	9.7	-5.9%	2,113.9	-1.4%	2,719.2	-2.9%	6,890.9	-4.5%	123.6	-4.6%	20,014.5	-3.1%
2018	7,165.4	0.7%	979.4	-6.0%	9.5	-1.5%	2,128.9	0.7%	2,701.6	-0.6%	6,789.9	-1.5%	120.6	-2.4%	19,895.2	-0.6%
2019	7,120.5	-0.6%	962.0	-1.8%	10.5	9.9%	2,155.4	1.2%	2,693.4	-0.3%	6,536.3	-3.7%	101.2	-16.1%	19,579.3	-1.6%
2020	6,973.9	-2.1%	857.7	-10.8%	4.6	-56.5%	2,086.1	-3.2%	2,633.9	-2.2%	6,414.6	-1.9%	95.0	-6.2%	19,065.7	-2.6%
2021	7,523.9	7.9%	956.4	11.5%	-	-100.0%	1,937.7	-7.1%	2,435.5	-7.5%	6,049.2	-5.7%	77.9	-18.0%	18,980.6	-0.4%
2022	7,207.3	-4.2%	953.7	-0.3%	-		2,029.7	4.7%	2,519.1	3.4%	6,180.1	2.2%	74.2	-4.7%	18,964.1	-0.1%
2023	7,287.0	1.1%	985.1	3.3%	-		2,044.4	0.7%	2,444.6	-3.0%	6,262.6	1.3%	76.3	2.7%	19,100.1	0.7%
2024	7,310.2	0.3%	985.6	0.1%	-		2,052.4	0.4%	2,441.8	-0.1%	6,243.2	-0.3%	81.8	7.3%	19,114.9	0.1%
2025	7,444.6	1.8%	1,003.8	1.8%	-		2,069.0	0.8%	2,460.5	0.8%	6,254.0	0.2%	81.4	-0.5%	19,313.4	1.0%
2026	7,575.1	1.8%	1,021.5	1.8%	-		2,083.4	0.7%	2,476.3	0.6%	6,246.4	-0.1%	81.0	-0.5%	19,483.8	0.9%
2027	7,743.7	2.2%	1,044.4	2.2%	-		2,099.3	0.8%	2,493.6	0.7%	6,237.5	-0.1%	80.7	-0.5%	19,699.1	1.1%
2028	7,994.0	3.2%	1,078.3	3.3%	-		2,125.4	1.2%	2,522.8	1.2%	6,259.8	0.4%	80.4	-0.3%	20,060.8	1.8%
Annual Growth Rates:																
prior 15 years		-0.6%		2.7%		-100.0%		-0.6%		-1.1%		-1.6%		-3.9%		-0.9%
prior 10 years		-0.7%		-0.9%		-100.0%		-0.6%		-1.4%		-1.6%		-5.3%		-1.1%
prior 5 years		0.3%		0.1%		-100.0%		-0.8%		-2.0%		-1.6%		-8.8%		-0.8%
BASE YEAR:		**2023**														
next 5 years		1.9%		1.8%				0.8%		0.6%		0.0%		1.1%		1.0%

2.4. Forecasted Fiscal Year Customer Counts by Rate Class

ANNUAL CUSTOMER COUNTS, FISCAL YEAR by Rate Code

FISCAL YEAR	RI		R2		R4		G1		G2		G3		SL		TOTAL	
2008	1,004,319		98,164		213		144,578		12,400		3,263		1,530		1,264,466	
2009	998,210	-0.6%	106,031	8.0%	203	-4.4%	144,239	-0.2%	12,408	0.1%	3,270	0.2%	1,774	16.0%	1,266,135	0.1%
2010	990,041	-0.8%	122,789	15.8%	200	-1.6%	145,486	0.9%	12,647	1.9%	3,243	-0.8%	2,186	23.3%	1,276,594	0.8%
2011	991,884	0.2%	129,029	5.1%	211	5.4%	145,581	0.1%	13,731	8.6%	3,467	6.9%	2,525	15.5%	1,286,428	0.8%
2012	986,245	-0.6%	137,655	6.7%	195	-7.8%	148,423	2.0%	12,399	-9.7%	3,199	-7.7%	2,834	12.2%	1,290,950	0.4%
2013	980,792	-0.6%	146,624	6.5%	194	-0.4%	149,337	0.6%	12,441	0.3%	3,190	-0.3%	3,233	14.1%	1,295,811	0.4%
2014	978,363	-0.2%	152,401	3.9%	189	-2.6%	150,002	0.4%	12,477	0.3%	3,186	-0.1%	3,424	5.9%	1,300,042	0.3%
2015	976,038	-0.2%	159,200	4.5%	192	1.6%	151,163	0.8%	12,493	0.1%	3,202	0.5%	3,469	1.3%	1,305,757	0.4%
2016	975,802	0.0%	168,402	5.8%	175	-8.8%	152,154	0.7%	12,447	-0.4%	3,182	-0.6%	3,342	-3.7%	1,315,504	0.7%
2017	988,309	1.3%	150,109	-10.9%	160	-8.3%	152,211	0.0%	12,278	-1.4%	3,143	-1.2%	3,253	-2.7%	1,309,464	-0.5%
2018	1,005,161	1.7%	142,111	-5.3%	147	-8.4%	154,562	1.5%	12,230	-0.4%	3,130	-0.4%	3,241	-0.4%	1,320,582	0.8%
2019	1,013,979	0.9%	138,949	-2.2%	134	-8.6%	155,602	0.7%	12,349	1.0%	3,136	0.2%	3,215	-0.8%	1,327,363	0.5%
2020	1,032,465	1.8%	130,499	-6.1%	85	-36.7%	156,894	0.8%	12,403	0.4%	3,165	0.9%	3,184	-0.9%	1,338,695	0.9%
2021	1,032,956	0.0%	135,777	4.0%	-	-100.0%	156,546	-0.2%	12,168	-1.9%	3,151	-0.4%	3,121	-2.0%	1,343,718	0.4%
2022	1,045,005	1.2%	139,266	2.6%	-		156,464	-0.1%	11,898	-2.2%	3,088	-2.0%	3,090	-1.0%	1,358,810	1.1%
2023	1,044,365	-0.1%	142,465	2.3%	-		157,292	0.5%	11,840	-0.5%	3,125	1.2%	3,097	0.2%	1,362,185	0.2%
2024	1,043,380	-0.1%	140,867	-1.1%	-		158,398	0.7%	12,043	1.7%	3,180	1.8%	3,081	-0.5%	1,360,949	-0.1%
2025	1,046,391	0.3%	141,267	0.3%	-		158,942	0.3%	12,096	0.4%	3,208	0.9%	3,056	-0.8%	1,364,960	0.3%
2026	1,049,373	0.3%	141,663	0.3%	-		159,428	0.3%	12,135	0.3%	3,220	0.4%	3,029	-0.9%	1,368,848	0.3%
2027	1,051,721	0.2%	141,976	0.2%	-		159,793	0.2%	12,161	0.2%	3,224	0.1%	3,001	-0.9%	1,371,875	0.2%
2028	1,053,649	0.2%	142,232	0.2%	-		160,085	0.2%	12,179	0.2%	3,225	0.0%	2,975	-0.9%	1,374,346	0.2%
Annual Growth Rates:																
prior 15 years		0.3%		2.5%		-100.0%		0.6%		-0.3%		-0.3%		4.8%		0.5%
prior 10 years		0.6%		-0.3%		-100.0%		0.5%		-0.5%		-0.2%		-0.4%		0.5%
prior 5 years		0.8%		0.0%		-100.0%		0.4%		-0.6%		0.0%		-0.9%		0.6%
BASE YEAR:		**2023**														
next 5 years		0.2%		0.0%				0.4%		0.6%		0.6%		-0.8%		0.2%

3. Nantucket Electric Company

3.1. Forecasted Fiscal Year Deliveries by Revenue Class

ANNUAL GWh (*and percent growth*) FISCAL YEAR (Historicals & Projections: Weather-Normal) by Revenue Class
After Energy Efficiency, Solarr, Electric Vehicle, and Electric Hear Pump Impacts

FISCAL YEAR	RESIDENTIAL Non-Heating		Elec Heating		RESIDENTIAL Total		COMMERCIAL		INDUSTRIAL		StreetLighting & Other		TOTAL	
2008	93.3		1.9		95.3		49.4		0.8		0.3		145.8	
2009	92.1	-1.3%	1.7	-9.8%	93.8	-1.5%	49.1	-0.6%	0.9	9.2%	0.3	8.1%	144.1	-1.1%
2010	92.1	0.0%	1.7	-1.7%	93.8	-0.1%	50.7	3.2%	1.0	4.3%	0.3	-1.3%	145.7	1.1%
2011	88.1	-4.3%	1.5	-14.6%	89.6	-4.5%	48.8	-3.8%	1.0	6.2%	0.3	-1.7%	139.6	-4.1%
2012	91.6	3.9%	1.5	3.5%	93.1	3.9%	50.1	2.7%	1.0	1.9%	0.3	0.2%	144.5	3.5%
2013	93.5	2.0%	1.5	-0.1%	95.0	2.0%	49.5	-1.2%	1.0	-2.5%	0.3	-0.3%	145.7	0.8%
2014	101.7	8.8%	1.7	10.7%	103.4	8.8%	52.2	5.6%	1.0	-6.1%	0.3	1.1%	156.8	7.6%
2015	105.4	3.6%	1.7	1.5%	107.1	3.6%	54.2	3.9%	0.9	-1.6%	0.3	-0.9%	162.5	3.7%
2016	98.4	-6.6%	1.6	-8.3%	100.0	-6.6%	50.6	-6.7%	1.0	10.6%	0.3	-0.1%	151.9	-6.5%
2017	104.3	5.9%	1.6	1.9%	105.8	5.9%	51.2	1.1%	1.0	-7.8%	0.3	0.1%	158.2	4.2%
2018	111.4	6.8%	1.7	9.1%	113.1	6.9%	59.8	17.0%	0.7	-24.9%	0.3	0.4%	173.9	9.9%
2019	111.1	-0.3%	1.7	-3.9%	112.8	-0.3%	57.4	-4.1%	0.7	-3.5%	0.3	1.0%	171.1	-1.6%
2020	112.5	1.3%	1.6	-0.9%	114.2	1.2%	53.9	-6.0%	0.6	-7.6%	0.3	-1.2%	169.0	-1.2%
2021	118.7	5.5%	1.7	2.0%	120.4	5.5%	53.7	-0.5%	0.6	-9.0%	0.3	-0.3%	174.9	3.5%
2022	110.1	-7.3%	1.5	-8.6%	111.6	-7.3%	50.6	-5.8%	0.7	18.9%	0.3	-0.6%	163.1	-6.8%
2023	108.1	-1.8%	1.4	-6.8%	109.6	-1.8%	48.4	-4.4%	0.8	12.7%	0.2	-8.0%	158.9	-2.6%
2024	111.5	3.1%	1.4	0.8%	113.0	3.1%	51.1	5.7%	0.7	-5.0%	0.3	9.3%	165.1	3.9%
2025	114.5	2.7%	1.5	4.6%	116.1	2.7%	52.1	2.0%	0.7	-2.0%	0.3	0.0%	169.2	2.5%
2026	117.4	2.5%	1.6	4.0%	119.0	2.5%	53.1	1.8%	0.7	-1.9%	0.3	0.0%	173.0	2.3%
2027	120.2	2.4%	1.6	3.0%	121.8	2.4%	54.0	1.8%	0.7	-1.8%	0.3	0.0%	176.8	2.2%
2028	124.4	3.5%	1.7	4.1%	126.1	3.5%	55.5	2.7%	0.7	-1.7%	0.3	0.0%	182.6	3.3%
Annual Growth Rates:														
prior 15 years		1.0%		-2.0%		0.9%		-0.1%		-0.5%		-0.3%		0.6%
prior 10 years		1.5%		-0.5%		1.4%		-0.2%		-2.6%		-0.9%		0.9%
prior 5 years		-0.6%		-3.7%		-0.6%		-4.2%		1.7%		-1.9%		-1.8%
BASE YEAR:		**2023**												
next 5 years		2.9%		3.3%		2.9%		2.8%		-2.5%		1.8%		2.8%

3.2. Forecasted Fiscal Year Customer Counts by Revenue Class

ANNUAL CUSTOMER COUNTS, FISCAL YEAR by Revenue Class

CALENDAR YEAR	RESIDENTIAL Non-Heating		Elec Heating		RESIDENTIAL Total		COMMERCIAL		INDUSTRIAL		StreetLighting & Other		TOTAL	
2008	10,784		298		11,082		1,348		4		7		12,442	
2009	10,926	1.3%	285	-4.6%	11,210	1.2%	1,402	4.0%	4	-10.4%	6	-11.9%	12,622	1.4%
2010	10,998	0.7%	280	-1.7%	11,277	0.6%	1,437	2.5%	4	-2.3%	6	-2.7%	12,724	0.8%
2011	11,032	0.3%	275	-1.8%	11,307	0.3%	1,456	1.3%	3	-14.3%	6	0.0%	12,772	0.4%
2012	11,085	0.5%	265	-3.3%	11,350	0.4%	1,465	0.6%	4	27.8%	6	0.0%	12,825	0.4%
2013	11,155	0.6%	256	-3.5%	11,411	0.5%	1,475	0.7%	4	-2.2%	6	0.0%	12,896	0.6%
2014	11,203	0.4%	250	-2.4%	11,453	0.4%	1,515	2.7%	4	-4.4%	6	0.0%	12,977	0.6%
2015	11,293	0.8%	239	-4.2%	11,532	0.7%	1,549	2.3%	4	2.3%	6	0.0%	13,091	0.9%
2016	11,370	0.7%	235	-1.7%	11,605	0.6%	1,575	1.7%	4	9.1%	6	0.0%	13,190	0.8%
2017	11,509	1.2%	228	-3.2%	11,737	1.1%	1,606	1.9%	4	-4.2%	6	0.0%	13,353	1.2%
2018	11,630	1.0%	180	-20.8%	11,810	0.6%	1,624	1.1%	4	4.3%	6	0.0%	13,444	0.7%
2019	11,787	1.3%	177	-1.7%	11,964	1.3%	1,639	0.9%	4	0.0%	6	0.0%	13,613	1.3%
2020	11,769	-0.2%	174	-2.1%	11,942	-0.2%	1,622	-1.0%	4	0.0%	6	0.0%	13,574	-0.3%
2021	12,048	2.4%	174	0.4%	12,223	2.3%	1,676	3.3%	4	-2.1%	6	0.0%	13,909	2.5%
2022	12,166	1.0%	172	-1.1%	12,338	0.9%	1,713	2.2%	4	2.1%	6	0.0%	14,061	1.1%
2023	12,286	1.0%	170	-1.0%	12,456	1.0%	1,711	-0.1%	4	0.0%	6	0.0%	14,178	0.8%
2024	12,307	0.2%	169	-1.1%	12,476	0.2%	1,732	1.2%	4	0.0%	6	0.0%	14,218	0.3%
2025	12,350	0.4%	167	-0.9%	12,517	0.3%	1,754	1.2%	4	0.0%	6	0.0%	14,281	0.4%
2026	12,423	0.6%	166	-1.0%	12,589	0.6%	1,777	1.3%	4	0.0%	6	0.0%	14,375	0.7%
2027	12,512	0.7%	164	-1.0%	12,676	0.7%	1,801	1.4%	4	0.0%	6	0.0%	14,486	0.8%
2028	12,607	0.8%	162	-1.0%	12,770	0.7%	1,826	1.4%	4	0.0%	6	0.0%	14,605	0.8%
Annual Growth Rates:														
prior 15 years		0.9%		-3.7%		0.8%		1.6%		0.0%		-1.0%		0.9%
prior 10 years		1.0%		-4.0%		0.9%		1.5%		0.6%		0.0%		1.0%
prior 5 years		1.1%		-1.1%		1.1%		1.1%		0.0%		0.0%		1.1%
BASE YEAR:		**2023**												
next 5 years		0.5%		-1.0%		0.5%		1.3%		0.0%		0.0%		0.6%

3.3. Forecasted Fiscal Year Deliveries by Rate Class

ANNUAL GWh (*and percent growth*) FISCAL YEAR (Historicals: Actuals; Projections: Weather-Normal) by Rate Code

After Energy Efficiency, Solar and Electric Vehicle Impacts

FISCAL YEAR	RI		R2		G1		G2		G3		SL		TOTAL	
2008	92.9		1.0		24.6		16.4		8.3		0.3		143.6	
2009	93.1	0.1%	1.1	10.6%	24.4	-0.9%	16.6	0.8%	8.5	2.5%	0.3	8.4%	143.9	0.3%
2010	88.9	-4.5%	1.3	26.1%	24.6	0.8%	16.5	-0.7%	8.6	1.3%	0.3	-1.2%	140.2	-2.6%
2011	92.7	4.3%	1.5	8.6%	25.2	2.5%	15.9	-3.3%	9.8	13.7%	0.3	-1.7%	145.4	3.7%
2012	90.3	-2.6%	1.8	22.7%	22.9	-9.2%	16.1	0.8%	12.0	22.2%	0.3	0.2%	143.3	-1.4%
2013	96.4	6.8%	1.9	5.0%	23.9	4.2%	16.5	2.6%	11.2	-6.6%	0.3	-0.3%	150.1	4.8%
2014	101.7	5.5%	2.0	6.3%	24.0	0.4%	17.6	6.6%	11.0	-2.1%	0.3	1.1%	156.5	4.2%
2015	101.2	-0.5%	2.0	1.3%	24.1	0.5%	16.8	-4.2%	12.1	10.8%	0.3	-0.9%	156.6	0.1%
2016	100.9	-0.3%	2.0	-2.9%	23.6	-1.9%	16.7	-0.7%	12.8	5.3%	0.3	-0.1%	156.3	-0.2%
2017	104.6	3.6%	2.0	2.6%	22.8	-3.7%	16.8	0.8%	12.9	0.8%	0.3	0.1%	159.3	2.0%
2018	106.7	2.0%	1.9	-5.0%	23.8	4.7%	17.8	5.9%	16.8	30.6%	0.3	0.4%	167.4	5.0%
2019	113.5	6.4%	1.6	-18.9%	25.6	7.5%	18.8	5.1%	13.9	-17.4%	0.3	1.0%	173.7	3.7%
2020	111.5	-1.8%	1.2	-24.2%	25.1	-1.9%	18.2	-3.2%	11.0	-21.1%	0.3	-1.2%	167.2	-3.7%
2021	120.5	8.1%	1.4	19.6%	22.7	-9.7%	15.9	-12.2%	16.6	51.3%	0.3	-0.3%	177.4	6.1%
2022	121.1	0.5%	1.6	10.3%	25.1	10.8%	17.5	9.9%	13.5	-18.4%	0.3	-0.6%	179.1	1.0%
2023	114.2	-5.7%	1.3	-13.9%	22.8	-9.2%	16.4	-6.6%	12.4	-8.4%	0.2	-8.1%	167.4	-6.5%
2024	111.5	-2.4%	1.5	11.5%	23.1	1.1%	16.2	-0.9%	12.5	0.9%	0.3	9.3%	165.1	-1.4%
2025	114.6	2.7%	1.5	2.7%	23.5	2.0%	16.5	2.0%	12.7	1.8%	0.3	0.0%	169.2	2.5%
2026	117.4	2.5%	1.6	2.5%	24.0	1.8%	16.8	1.8%	13.0	1.7%	0.3	0.0%	173.0	2.3%
2027	120.2	2.4%	1.6	2.4%	24.4	1.8%	17.1	1.8%	13.2	1.6%	0.3	0.0%	176.8	2.2%
2028	124.5	3.5%	1.7	3.5%	25.1	2.7%	17.6	2.7%	13.5	2.5%	0.3	0.0%	182.6	3.3%
Annual Growth Rates:														
prior 15 years		1.4%		2.2%		-0.5%		0.0%		2.7%		-0.3%		1.0%
prior 10 years		1.7%		-3.3%		-0.4%		-0.1%		1.0%		-0.9%		1.1%
prior 5 years		1.4%		-6.9%		-0.8%		-1.7%		-5.9%		-1.9%		0.0%
BASE YEAR:		**2023**												
next 5 years		1.7%		4.5%		1.9%		1.5%		1.7%		1.8%		1.8%

3.4. Forecasted Fiscal Year Customer Counts by Rate Class

ANNUAL CUSTOMER COUNTS, FISCAL YEAR by Rate Code														
FISCAL YEAR	RI		R2		G1		G2		G3		SL		TOTAL	
2008	10,969		111		1,292		57		6		6		12,442	
2009	11,089	1.1%	118	6.8%	1,342	3.9%	59	3.6%	6	-1.3%	7	19.5%	12,622	1.4%
2010	11,113	0.2%	165	39.3%	1,371	2.2%	62	4.0%	6	0.5%	7	3.3%	12,724	0.8%
2011	11,141	0.3%	177	7.4%	1,373	0.1%	67	8.2%	7	20.3%	7	-0.6%	12,772	0.4%
2012	11,154	0.1%	212	19.8%	1,384	0.8%	59	-11.2%	8	13.6%	7	0.6%	12,825	0.4%
2013	11,209	0.5%	211	-0.5%	1,397	0.9%	64	7.3%	9	5.3%	7	0.0%	12,896	0.6%
2014	11,252	0.4%	209	-0.9%	1,436	2.8%	65	1.5%	8	-2.3%	7	0.0%	12,977	0.6%
2015	11,338	0.8%	217	3.6%	1,454	1.3%	66	1.5%	10	14.6%	7	0.0%	13,091	0.9%
2016	11,400	0.5%	220	1.3%	1,486	2.2%	68	3.5%	10	3.2%	7	0.0%	13,190	0.8%
2017	11,534	1.2%	214	-2.6%	1,514	1.9%	73	8.1%	11	8.5%	7	-0.4%	13,353	1.2%
2018	11,617	0.7%	203	-5.0%	1,532	1.2%	74	0.5%	11	1.5%	7	0.5%	13,444	0.7%
2019	11,802	1.6%	158	-22.1%	1,555	1.5%	77	4.4%	13	18.0%	7	0.0%	13,613	1.3%
2020	11,803	0.0%	138	-12.7%	1,534	-1.3%	79	2.6%	12	-4.2%	7	-0.2%	13,574	-0.3%
2021	12,070	2.3%	149	7.8%	1,589	3.6%	79	-0.4%	14	13.2%	7	0.2%	13,909	2.5%
2022	12,171	0.8%	170	14.1%	1,622	2.0%	80	1.6%	12	-17.6%	7	0.0%	14,061	1.1%
2023	12,290	1.0%	162	-5.0%	1,630	0.5%	78	-2.8%	11	-6.7%	7	0.1%	14,178	0.8%
2024	12,310	0.2%	165	2.2%	1,646	1.0%	80	2.4%	11	2.9%	7	0.1%	14,218	0.3%
2025	12,351	0.3%	166	0.3%	1,666	1.2%	81	1.2%	11	1.1%	7	0.2%	14,281	0.4%
2026	12,422	0.6%	167	0.6%	1,687	1.3%	82	1.3%	11	1.2%	7	0.2%	14,375	0.7%
2027	12,508	0.7%	168	0.7%	1,709	1.3%	83	1.3%	11	1.2%	7	0.2%	14,486	0.8%
2028	12,601	0.7%	169	0.7%	1,733	1.4%	84	1.4%	12	1.3%	7	0.2%	14,605	0.8%

Appendices

APPENDIX A1: DERs - Massachusetts Electric

MECO TOTAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

	DELIVERIES (50/50)						DER IMPACTS				
Calendar Year	Reconstituted (before DER impacts)	Forecast w/only EE Reduction	Forecast w/only PV Reduction	Forecast w/only EV Increase	Forecast w/only EHP Increase	Final Forecast (after all impacts)	EE Reduction	PV Reduction	EV Increase	EH Increase	Total Impacts
2007	23,160	22,113	23,159	23,160	23,160	**22,112**	(1,047)	(1)	0	0	(1,048)
2008	23,133	21,845	23,131	23,133	23,133	**21,843**	(1,288)	(1)	0	0	(1,289)
2009	22,983	21,424	22,980	22,983	22,983	**21,422**	(1,558)	(3)	0	0	(1,561)
2010	23,278	21,408	23,273	23,278	23,278	**21,403**	(1,870)	(5)	0	0	(1,875)
2011	23,585	21,379	23,576	23,585	23,585	**21,371**	(2,205)	(8)	0	0	(2,214)
2012	24,098	21,424	24,080	24,099	24,098	**21,407**	(2,674)	(18)	1	0	(2,691)
2013	24,567	21,352	24,527	24,569	24,567	**21,315**	(3,215)	(40)	2	0	(3,252)
2014	24,990	21,186	24,906	24,995	24,990	**21,106**	(3,805)	(84)	4	0	(3,884)
2015	25,396	20,940	25,214	25,402	25,396	**20,765**	(4,456)	(182)	7	0	(4,631)
2016	25,533	20,403	25,212	25,542	25,533	**20,092**	(5,129)	(321)	9	0	(5,441)
2017	26,130	20,309	25,700	26,143	26,130	**19,892**	(5,820)	(430)	13	0	(6,238)
2018	26,718	20,167	26,212	26,738	26,718	**19,682**	(6,551)	(506)	21	0	(7,036)
2019	26,916	19,676	26,336	26,946	26,918	**19,127**	(7,241)	(580)	30	1	(7,789)
2020	27,477	19,586	26,808	27,516	27,482	**18,962**	(7,891)	(669)	39	6	(8,515)
2021	28,300	19,825	27,529	28,354	28,312	**19,120**	(8,475)	(771)	54	12	(9,181)
2022	28,688	19,805	27,791	28,776	28,713	**19,022**	(8,882)	(897)	89	25	(9,666)
2023	29,097	19,916	28,063	29,244	29,149	**19,080**	(9,181)	(1,034)	147	52	(10,016)
2024	29,519	20,062	28,348	29,752	29,613	**19,218**	(9,457)	(1,171)	233	94	(10,301)
2025	29,936	20,220	28,636	30,286	30,081	**19,415**	(9,716)	(1,300)	350	144	(10,522)
2026	30,277	20,322	28,848	30,785	30,478	**19,602**	(9,955)	(1,429)	508	201	(10,674)
2027	30,698	20,522	29,140	31,421	30,969	**19,957**	(10,177)	(1,559)	722	271	(10,742)

Annual Growth Rates:											
prior 15 years	1.4%	-0.7%	1.2%	1.5%	1.4%	**-1.0%**	-2.2%	-0.2%	0.0%	0.0%	-2.4%
prior 10 years	1.8%	-0.8%	1.4%	1.8%	1.8%	**-1.2%**	-2.5%	-0.3%	0.0%	0.0%	-2.9%
prior 5 years	1.9%	-0.5%	1.6%	1.9%	1.9%	**-0.9%**	-2.4%	-0.3%	0.1%	0.0%	-2.8%
BASE YEAR: 2022											
next 5 years	1.4%	0.7%	1.0%	1.8%	1.5%	**1.0%**	-0.7%	-0.4%	0.4%	0.2%	-0.4%

MECO RESIDENTIAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

Calendar Year	Reconstituted (before DER impacts)	DELIVERIES (50/50): Forecast w/only EE Reduction	Forecast w/only PV Reduction	Forecast w/only EV Increase	Forecast w/only EHP Increase	Final Forecast (after all impacts)	DER IMPACTS: EE Reduction	PV Reduction	EV Increase	EH Increase	Total Impacts
2007	9,232	8,659	9,231	9,232	9,232	**8,658**	(573)	(1)	0	0	(574)
2008	9,329	8,621	9,328	9,329	9,329	**8,620**	(708)	(1)	0	0	(709)
2009	9,449	8,596	9,447	9,449	9,449	**8,594**	(853)	(3)	0	0	(856)
2010	9,717	8,722	9,713	9,717	9,717	**8,718**	(995)	(4)	0	0	(1,000)
2011	9,891	8,769	9,885	9,891	9,891	**8,763**	(1,122)	(7)	0	0	(1,129)
2012	10,167	8,866	10,154	10,168	10,167	**8,854**	(1,301)	(13)	1	0	(1,314)
2013	10,477	8,934	10,450	10,479	10,477	**8,910**	(1,542)	(27)	2	0	(1,567)
2014	10,602	8,756	10,541	10,605	10,602	**8,699**	(1,845)	(61)	4	0	(1,902)
2015	10,735	8,600	10,585	10,740	10,735	**8,456**	(2,135)	(150)	5	0	(2,279)
2016	10,849	8,410	10,572	10,856	10,849	**8,139**	(2,439)	(278)	7	0	(2,710)
2017	11,277	8,461	10,907	11,288	11,277	**8,103**	(2,815)	(370)	11	0	(3,174)
2018	11,774	8,530	11,343	11,792	11,774	**8,116**	(3,244)	(431)	17	0	(3,658)
2019	11,921	8,292	11,424	11,946	11,922	**7,822**	(3,628)	(497)	25	1	(4,099)
2020	12,865	8,859	12,292	12,897	12,870	**8,324**	(4,006)	(572)	33	6	(4,540)
2021	13,099	8,795	12,441	13,143	13,111	**8,194**	(4,303)	(658)	45	12	(4,905)
2022	13,331	8,898	12,561	13,404	13,355	**8,226**	(4,433)	(770)	73	24	(5,105)
2023	13,477	8,972	12,580	13,595	13,525	**8,242**	(4,505)	(896)	119	48	(5,234)
2024	13,692	9,117	12,669	13,875	13,777	**8,363**	(4,575)	(1,022)	184	85	(5,328)
2025	13,904	9,263	12,763	14,173	14,033	**8,521**	(4,641)	(1,141)	270	130	(5,383)
2026	14,082	9,385	12,822	14,469	14,263	**8,692**	(4,697)	(1,260)	386	180	(5,390)
2027	14,304	9,560	12,924	14,848	14,547	**8,968**	(4,744)	(1,380)	545	244	(5,336)

Annual Growth Rates:											
prior 15 years	2.5%	0.2%	2.1%	2.5%	2.5%	**-0.3%**	-2.3%	-0.4%	0.0%	0.0%	-2.8%
prior 10 years	2.7%	0.0%	2.1%	2.8%	2.8%	**-0.7%**	-2.7%	-0.6%	0.1%	0.0%	-3.5%
prior 5 years	3.4%	1.0%	2.9%	3.5%	3.4%	**0.3%**	-2.4%	-0.5%	0.1%	0.0%	-3.1%
BASE YEAR: 2022											
next 5 years	1.4%	1.4%	0.6%	2.1%	1.7%	**1.7%**	0.0%	-0.8%	0.6%	0.3%	0.3%

MECO COMMERCIAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

	DELIVERIES (50/50)						DER IMPACTS				
Calendar Year	Reconstituted (before DER impacts)	Forecast w/only EE Reduction	Forecast w/only PV Reduction	Forecast w/only EV Increase	Forecast w/only EHP Increase	Final Forecast (after all impacts)	EE Reduction	PV Reduction	EV Increase	EH Increase	Total Impacts
2007	9,815	9,484	9,815	9,815	9,815	**9,484**	(330)	(0)	0	0	(330)
2008	9,826	9,420	9,826	9,826	9,826	**9,420**	(406)	(0)	0	0	(406)
2009	9,779	9,282	9,779	9,779	9,779	**9,282**	(496)	(0)	0	0	(497)
2010	9,835	9,215	9,835	9,835	9,835	**9,214**	(620)	(1)	0	0	(621)
2011	9,977	9,203	9,976	9,977	9,977	**9,202**	(774)	(1)	0	0	(775)
2012	10,231	9,244	10,228	10,232	10,231	**9,240**	(988)	(4)	0	0	(992)
2013	10,366	9,155	10,356	10,366	10,366	**9,146**	(1,211)	(10)	0	0	(1,220)
2014	10,569	9,145	10,552	10,570	10,569	**9,129**	(1,424)	(17)	1	0	(1,441)
2015	10,819	9,126	10,795	10,820	10,819	**9,103**	(1,693)	(24)	1	0	(1,716)
2016	10,952	8,982	10,920	10,953	10,952	**8,951**	(1,970)	(32)	1	0	(2,001)
2017	11,157	8,948	11,112	11,159	11,157	**8,904**	(2,210)	(45)	2	0	(2,253)
2018	11,287	8,847	11,231	11,290	11,287	**8,794**	(2,440)	(56)	3	0	(2,493)
2019	11,450	8,774	11,387	11,454	11,450	**8,715**	(2,676)	(63)	4	0	(2,735)
2020	11,093	8,207	11,020	11,098	11,093	**8,139**	(2,886)	(73)	5	0	(2,954)
2021	11,529	8,422	11,443	11,536	11,529	**8,343**	(3,107)	(86)	7	0	(3,185)
2022	11,777	8,455	11,680	11,788	11,777	**8,371**	(3,322)	(97)	12	1	(3,406)
2023	11,916	8,418	11,811	11,938	11,919	**8,337**	(3,499)	(105)	22	3	(3,579)
2024	12,114	8,454	12,001	12,153	12,121	**8,386**	(3,660)	(114)	39	7	(3,728)
2025	12,320	8,508	12,199	12,383	12,332	**8,461**	(3,812)	(121)	63	12	(3,859)
2026	12,500	8,544	12,371	12,596	12,517	**8,526**	(3,957)	(129)	95	17	(3,974)
2027	12,710	8,615	12,573	12,850	12,732	**8,640**	(4,095)	(137)	140	22	(4,071)

Annual Growth Rates:											
prior 15 years	1.2%	-0.8%	1.2%	1.2%	1.2%	**-0.8%**	-2.0%	-0.1%	0.0%	0.0%	-2.1%
prior 10 years	1.4%	-0.9%	1.3%	1.4%	1.4%	**-1.0%**	-2.3%	-0.1%	0.0%	0.0%	-2.4%
prior 5 years	1.1%	-1.1%	1.0%	1.1%	1.1%	**-1.2%**	-2.2%	-0.1%	0.0%	0.0%	-2.3%
BASE YEAR: 2022											
next 5 years	1.5%	0.4%	1.5%	1.7%	1.6%	**0.6%**	-1.2%	-0.1%	0.2%	0.0%	-0.9%

MECO INDUSTRIAL Deliveries (weather-normalize, 50/50) (GWh)   (before & after DERs)

	DELIVERIES (50/50)						DER IMPACTS				
Calendar Year	Reconstituted (before DER impacts)	Forecast w/only EE Reduction	Forecast w/only PV Reduction	Forecast w/only EV Increase	Forecast w/only EHP Increase	Final Forecast (after all impacts)	EE Reduction	PV Reduction	EV Increase	EH Increase	Total Impacts
2007	4,004	3,860	4,004	4,004	4,004	**3,860**	(144)	(0)	0	0	(144)
2008	3,867	3,693	3,867	3,867	3,867	**3,693**	(174)	(0)	0	0	(174)
2009	3,645	3,437	3,645	3,645	3,645	**3,436**	(208)	(0)	0	0	(209)
2010	3,618	3,364	3,618	3,618	3,618	**3,364**	(254)	(0)	0	0	(254)
2011	3,605	3,296	3,604	3,605	3,605	**3,295**	(309)	(1)	0	0	(310)
2012	3,591	3,206	3,589	3,591	3,591	**3,205**	(384)	(1)	0	0	(386)
2013	3,618	3,157	3,615	3,619	3,618	**3,154**	(462)	(3)	0	0	(465)
2014	3,704	3,169	3,698	3,704	3,704	**3,163**	(535)	(6)	0	0	(541)
2015	3,741	3,114	3,733	3,742	3,741	**3,106**	(628)	(8)	0	0	(636)
2016	3,625	2,905	3,614	3,625	3,625	**2,895**	(720)	(11)	0	0	(730)
2017	3,595	2,800	3,580	3,596	3,595	**2,785**	(796)	(15)	1	0	(810)
2018	3,562	2,695	3,544	3,563	3,562	**2,678**	(867)	(19)	1	0	(884)
2019	3,475	2,538	3,454	3,476	3,475	**2,519**	(937)	(21)	1	0	(956)
2020	3,450	2,452	3,427	3,452	3,450	**2,430**	(998)	(24)	2	0	(1,020)
2021	3,619	2,554	3,592	3,621	3,619	**2,529**	(1,065)	(27)	2	0	(1,090)
2022	3,523	2,395	3,492	3,526	3,523	**2,368**	(1,128)	(31)	4	0	(1,155)
2023	3,640	2,462	3,607	3,646	3,640	**2,436**	(1,178)	(33)	6	1	(1,203)
2024	3,649	2,427	3,614	3,660	3,651	**2,405**	(1,222)	(35)	11	2	(1,245)
2025	3,649	2,386	3,612	3,667	3,652	**2,369**	(1,263)	(37)	17	3	(1,280)
2026	3,631	2,330	3,592	3,657	3,636	**2,321**	(1,302)	(39)	26	4	(1,310)
2027	3,622	2,285	3,581	3,660	3,628	**2,287**	(1,337)	(42)	38	6	(1,336)

Annual Growth Rates:											
prior 15 years	-0.9%	-3.1%	-0.9%	-0.8%	-0.9%	**-3.2%**	-2.3%	-0.1%	0.0%	0.0%	-2.4%
prior 10 years	-0.2%	-2.9%	-0.3%	-0.2%	-0.2%	**-3.0%**	-2.7%	-0.1%	0.0%	0.0%	-2.8%
prior 5 years	-0.4%	-3.1%	-0.5%	-0.4%	-0.4%	**-3.2%**	-2.7%	-0.1%	0.0%	0.0%	-2.8%
BASE YEAR: 2022											
next 5 years	0.6%	-0.9%	0.5%	0.7%	0.6%	**-0.7%**	-1.5%	-0.1%	0.2%	0.0%	-1.3%

APPENDIX A2: DERs - Nantucket Electric

NANTUCKET TOTAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

Calendar Year	DELIVERIES (50/50): Reconstituted (before DER impacts)	Forecast w/only EE Reduction	Forecast w/only PV Reduction	Forecast w/only EV Increase	Forecast w/only EHP Increase	Final Forecast (after all impacts)	DER IMPACTS: EE Reduction	PV Reduction	EV Increase	EH Increase	Total Impacts
2007	151	146	151	151	151	**146**	(5)	(0)	0	0	(5)
2008	152	146	152	152	152	**146**	(6)	(0)	0	0	(6)
2009	154	146	154	154	154	**146**	(8)	(0)	0	0	(8)
2010	149	139	149	149	149	**139**	(9)	(0)	0	0	(9)
2011	157	146	157	157	157	**145**	(11)	(0)	0	0	(11)
2012	157	143	157	157	157	**143**	(13)	(0)	0	0	(14)
2013	170	154	170	170	170	**154**	(16)	(0)	0	0	(16)
2014	182	163	182	182	182	**163**	(19)	(0)	0	0	(20)
2015	177	155	176	177	177	**154**	(22)	(1)	0	0	(23)
2016	187	161	185	187	187	**159**	(26)	(2)	0	0	(27)
2017	201	172	199	201	201	**170**	(29)	(2)	0	0	(31)
2018	205	172	203	205	205	**170**	(33)	(3)	0	0	(35)
2019	212	175	209	212	212	**173**	(36)	(3)	0	0	(39)
2020	213	173	209	213	213	**170**	(40)	(3)	0	0	(43)
2021	208	166	204	208	208	**162**	(43)	(4)	0	0	(46)
2022	213	168	209	213	213	**164**	(45)	(5)	0	0	(49)
2023	214	168	209	215	214	**164**	(46)	(5)	1	0	(50)
2024	220	172	214	221	220	**168**	(48)	(6)	1	0	(52)
2025	225	176	218	227	226	**172**	(49)	(7)	2	1	(53)
2026	229	179	222	232	230	**175**	(50)	(7)	2	1	(54)
2027	235	184	228	239	237	**181**	(51)	(8)	3	1	(54)
Annual Growth Rates:											
prior 15 years	2.3%	1.0%	2.2%	2.3%	2.3%	**0.8%**	-1.4%	-0.1%	0.0%	0.0%	-1.5%
prior 10 years	3.1%	1.6%	2.9%	3.1%	3.1%	**1.4%**	-1.5%	-0.2%	0.0%	0.0%	-1.7%
prior 5 years	1.2%	-0.4%	1.0%	1.2%	1.2%	**-0.6%**	-1.6%	-0.2%	0.0%	0.0%	-1.8%
BASE YEAR: 2022											
next 5 years	2.0%	1.8%	1.8%	2.3%	2.1%	**2.0%**	-0.2%	-0.3%	0.3%	0.1%	-0.1%

NANTUCKET RESIDENTIAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

	DELIVERIES (50/50)						DER IMPACTS				
Calendar Year	Reconstituted (before DER impacts)	Forecast w/only EE Reduction	Forecast w/only PV Reduction	Forecast w/only EV Increase	Forecast w/only EHP Increase	Final Forecast (after all impacts)	EE Reduction	PV Reduction	EV Increase	EH Increase	Total Impacts
2007	99	96	99	99	99	**96**	(2.9)	(0.0)	0.0	0.0	(2.9)
2008	99	95	99	99	99	**95**	(3.6)	(0.0)	0.0	0.0	(3.6)
2009	99	94	99	99	99	**94**	(4.3)	(0.0)	0.0	0.0	(4.3)
2010	94	89	94	94	94	**89**	(5.0)	(0.0)	0.0	0.0	(5.0)
2011	99	94	99	99	99	**94**	(5.6)	(0.0)	0.0	0.0	(5.7)
2012	99	93	99	99	99	**93**	(6.5)	(0.1)	0.0	0.0	(6.6)
2013	109	102	109	109	109	**102**	(7.8)	(0.1)	0.0	0.0	(7.9)
2014	116	107	116	116	116	**107**	(9.3)	(0.3)	0.0	0.0	(9.6)
2015	113	102	112	113	113	**101**	(10.7)	(0.8)	0.0	0.0	(11.5)
2016	119	107	118	119	119	**106**	(12.3)	(1.4)	0.0	0.0	(13.6)
2017	127	113	125	127	127	**111**	(14.1)	(1.9)	0.1	0.0	(15.9)
2018	131	115	129	131	131	**112**	(16.3)	(2.2)	0.1	0.0	(18.4)
2019	134	116	132	135	134	**114**	(18.2)	(2.5)	0.1	0.0	(20.6)
2020	141	121	138	141	141	**118**	(20.1)	(2.9)	0.2	0.0	(22.8)
2021	136	114	133	136	136	**111**	(21.6)	(3.3)	0.2	0.1	(24.6)
2022	138	116	135	139	139	**113**	(22.3)	(3.9)	0.4	0.1	(25.7)
2023	138	116	134	139	138	**112**	(22.6)	(4.5)	0.6	0.2	(26.3)
2024	142	119	137	143	142	**115**	(23.0)	(5.1)	0.9	0.4	(26.8)
2025	145	122	139	147	146	**118**	(23.3)	(5.7)	1.4	0.7	(27.0)
2026	148	124	142	150	149	**121**	(23.6)	(6.3)	1.9	0.9	(27.1)
2027	152	128	145	155	153	**125**	(23.8)	(6.9)	2.7	1.2	(26.8)
Annual Growth Rates:											
prior 15 years	2.3%	1.3%	2.1%	2.3%	2.3%	**1.1%**	-1.0%	-0.2%	0.0%	0.0%	-1.2%
prior 10 years	3.4%	2.3%	3.1%	3.4%	3.4%	**2.0%**	-1.1%	-0.3%	0.0%	0.0%	-1.4%
prior 5 years	1.7%	0.5%	1.4%	1.8%	1.7%	**0.3%**	-1.2%	-0.3%	0.0%	0.0%	-1.4%
BASE YEAR: 2022											
next 5 years	1.9%	2.0%	1.5%	2.2%	2.0%	**2.1%**	0.1%	-0.4%	0.3%	0.1%	0.2%

NANTUCKET COMMERCIAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

Calendar Year	Reconstituted (before DER impacts)	Forecast w/only EE Reduction	Forecast w/only PV Reduction	Forecast w/only EV Increase	Forecast w/only EHP Increase	Final Forecast (after all impacts)	EE Reduction	PV Reduction	EV Increase	EH Increase	Total Impacts
	DELIVERIES (50/50)						DER IMPACTS				
2007	51	49	51	51	51	**49**	(2.4)	(0.0)	0.0	0.0	(2.4)
2008	52	50	52	52	52	**50**	(2.9)	(0.0)	0.0	0.0	(2.9)
2009	54	50	54	54	54	**50**	(3.5)	(0.0)	0.0	0.0	(3.5)
2010	53	49	53	53	53	**49**	(4.3)	(0.0)	0.0	0.0	(4.3)
2011	56	51	56	56	56	**51**	(5.4)	(0.0)	0.0	0.0	(5.4)
2012	56	49	56	56	56	**49**	(6.8)	(0.0)	0.0	0.0	(6.8)
2013	59	51	59	59	59	**51**	(8.3)	(0.1)	0.0	0.0	(8.3)
2014	65	55	64	65	65	**55**	(9.7)	(0.1)	0.0	0.0	(9.8)
2015	63	51	63	63	63	**51**	(11.5)	(0.2)	0.0	0.0	(11.6)
2016	66	52	65	66	66	**52**	(13.3)	(0.2)	0.0	0.0	(13.5)
2017	73	58	72	73	73	**57**	(14.8)	(0.3)	0.0	0.0	(15.1)
2018	73	57	73	73	73	**57**	(16.3)	(0.4)	0.0	0.0	(16.7)
2019	76	58	76	76	76	**58**	(17.9)	(0.4)	0.0	0.0	(18.2)
2020	71	51	70	71	71	**51**	(19.2)	(0.5)	0.0	0.0	(19.7)
2021	71	50	70	71	71	**50**	(20.6)	(0.6)	0.0	0.0	(21.2)
2022	73	51	73	73	73	**51**	(22.0)	(0.6)	0.1	0.0	(22.6)
2023	74	51	74	75	74	**51**	(23.1)	(0.7)	0.1	0.0	(23.7)
2024	76	52	76	77	77	**52**	(24.2)	(0.7)	0.2	0.0	(24.7)
2025	78	53	78	79	78	**53**	(25.1)	(0.8)	0.3	0.1	(25.5)
2026	80	54	79	80	80	**54**	(26.0)	(0.8)	0.5	0.1	(26.3)
2027	82	55	81	83	82	**55**	(26.9)	(0.9)	0.7	0.1	(27.0)

Annual Growth Rates:											
prior 15 years	2.4%	0.3%	2.4%	2.4%	2.4%	**0.2%**	-2.1%	-0.1%	0.0%	0.0%	-2.2%
prior 10 years	2.7%	0.4%	2.6%	2.7%	2.7%	**0.3%**	-2.3%	-0.1%	0.0%	0.0%	-2.4%
prior 5 years	0.2%	-2.4%	0.1%	0.2%	0.2%	**-2.5%**	-2.5%	-0.1%	0.0%	0.0%	-2.7%
BASE YEAR: 2022											
next 5 years	2.3%	1.6%	2.3%	2.5%	2.4%	**1.7%**	-0.8%	0.0%	0.1%	0.0%	-0.6%

NANTUCKET INDUSTRIAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

	DELIVERIES (50/50)						DER IMPACTS				
Calendar Year	Reconstituted (before DER impacts)	Forecast w/only EE Reduction	Forecast w/only PV Reduction	Forecast w/only EV Increase	Forecast w/only EHP Increase	Final Forecast (after all impacts)	EE Reduction	PV Reduction	EV Increase	EH Increase	Total Impacts
2007	0.8	0.8	0.8	0.8	0.8	**0.8**	(0.0)	(0.0)	0.0	-	(0.0)
2008	1.0	0.9	1.0	1.0	1.0	**0.9**	(0.0)	(0.0)	(0.0)	-	(0.0)
2009	1.0	1.0	1.0	1.0	1.0	**1.0**	(0.0)	(0.0)	0.0	-	(0.0)
2010	1.0	1.0	1.0	1.0	1.0	**1.0**	(0.1)	(0.0)	0.0	-	(0.1)
2011	1.1	1.1	1.1	1.1	1.1	**1.1**	(0.1)	(0.0)	0.0	-	(0.1)
2012	1.1	1.0	1.1	1.1	1.1	**1.0**	(0.1)	(0.0)	0.0	-	(0.1)
2013	1.1	1.0	1.1	1.1	1.1	**1.0**	(0.1)	(0.0)	0.0	-	(0.1)
2014	1.1	0.9	1.1	1.1	1.1	**0.9**	(0.2)	(0.0)	0.0	-	(0.2)
2015	1.2	1.0	1.2	1.2	1.2	**1.0**	(0.2)	(0.0)	0.0	-	(0.2)
2016	1.2	1.0	1.2	1.2	1.2	**1.0**	(0.2)	(0.0)	0.0	-	(0.2)
2017	1.0	0.7	1.0	1.0	1.0	**0.7**	(0.3)	(0.0)	0.0	-	(0.3)
2018	1.0	0.7	1.0	1.0	1.0	**0.7**	(0.3)	(0.0)	0.0	-	(0.3)
2019	1.0	0.7	1.0	1.0	1.0	**0.7**	(0.3)	(0.0)	0.0	-	(0.3)
2020	0.8	0.5	0.8	0.8	0.8	**0.5**	(0.3)	(0.0)	0.0	-	(0.3)
2021	1.1	0.8	1.1	1.1	1.1	**0.7**	(0.3)	(0.0)	0.0	-	(0.3)
2022	1.1	0.8	1.1	1.1	1.1	**0.8**	(0.3)	(0.0)	0.0	-	(0.4)
2023	1.1	0.8	1.1	1.1	1.1	**0.7**	(0.4)	(0.0)	0.0	-	(0.4)
2024	1.1	0.7	1.1	1.1	1.1	**0.7**	(0.4)	(0.0)	0.0	-	(0.4)
2025	1.1	0.7	1.1	1.1	1.1	**0.7**	(0.4)	(0.0)	0.0	-	(0.4)
2026	1.1	0.7	1.1	1.1	1.1	**0.7**	(0.4)	(0.0)	0.0	-	(0.4)
2027	1.1	0.7	1.1	1.1	1.1	**0.7**	(0.4)	(0.0)	0.0	-	(0.4)

Annual Growth Rates:											
prior 15 years	2.0%	-0.3%	1.9%	2.0%	2.0%	**-0.4%**	-2.3%	-0.1%	0.0%	0.0%	-2.4%
prior 10 years	0.1%	-2.4%	0.1%	0.1%	0.1%	**-2.5%**	-2.6%	-0.1%	0.0%	0.0%	-2.7%
prior 5 years	2.9%	1.6%	2.8%	2.9%	2.9%	**1.5%**	-1.3%	-0.1%	0.0%	0.0%	-1.4%
BASE YEAR: 2022											
next 5 years	-0.4%	-2.5%	-0.5%	-0.3%	-0.4%	**-2.4%**	-2.1%	-0.1%	0.1%	0.0%	-2.1%

APPENDIX B1: MODELS - Massachusetts Electric

Model: MECO ELECTRIC RESIDENTIAL USE per CUST, recon Method (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	55060.2115	DFE	215
MSE	256.09401	Root MSE	16.00294
SBC	2071.47463	AIC	1998.73416
MAE	12.1253215	AICC	2003.05191
MAPE	1.60431157	HQC	2028.05647
Durbin-Watson	2.0235	Transformed Regression R-Square	0.9757
		Total R-Square	0.9856

Parameter Estimates						
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	-23899	814.4486	-29.34	<.0001	
time_trend	1	12.0828	0.4076	29.65	<.0001	
post_covid	1	56.3734	6.8860	8.19	<.0001	
hdd_jan	1	0.2138	0.005405	39.55	<.0001	
hdd_feb	1	0.1882	0.004668	40.31	<.0001	
hdd_mar	1	0.1586	0.004862	32.62	<.0001	
hdd_apr	1	0.1015	0.005819	17.45	<.0001	
cdd_jun	1	0.6833	0.0603	11.33	<.0001	
cdd_jul	1	0.9492	0.0232	40.93	<.0001	
cdd_aug	1	1.0569	0.0190	55.71	<.0001	
cdd_sep	1	1.0761	0.0298	36.15	<.0001	
cdd_oct	1	0.8445	0.1064	7.94	<.0001	
hdd_nov	1	0.0723	0.0107	6.74	<.0001	
hdd_dec	1	0.1674	0.007207	23.23	<.0001	
Bdays	1	14.4557	1.6194	8.93	<.0001	Number of Billing Days
sep09	1	38.5309	14.8473	2.60	0.0101	
jan07	1	40.6530	14.8134	2.74	0.0066	
aug14	1	53.4922	14.7760	3.62	0.0004	
aug20	1	67.2177	16.4733	4.08	<.0001	
jul20	1	58.1911	16.5027	3.53	0.0005	

Model: MECO ELECTRIC COMMERCIAL USE per CUST, recon Method (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	3772002.26	DFE	221
MSE	17068	Root MSE	130.64411
SBC	3036.03988	AIC	2984.0824
MAE	98.1251013	AICC	2986.26422
MAPE	1.81568453	HQC	3005.02691
Durbin-Watson	1.9580	Transformed Regression R-Square	0.8942
		Total R-Square	0.9128

Parameter Estimates

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	109.7597	292.2084	0.38	0.7076	
IDX_GDP	1	25.6033	1.1028	23.22	<.0001	idx_GDP
cdd_season	1	108.7127	39.4678	2.75	0.0064	
hdd_season	1	-378.6847	41.8491	-9.05	<.0001	
cdd_season*cdd_5	1	3.3427	0.1541	21.69	<.0001	
hdd_season*hdd_5	1	0.8425	0.0516	16.33	<.0001	
Bdays	1	91.0722	8.9117	10.22	<.0001	Number of Billing Days
sep08	1	439.0602	129.3285	3.39	0.0008	
apr10	1	-319.9081	130.5865	-2.45	0.0151	
jun16	1	433.4192	130.2715	3.33	0.0010	
may20	1	-316.9232	134.2200	-2.36	0.0191	
jun20	1	-282.2918	131.8969	-2.14	0.0334	
aug20	1	461.7211	134.7054	3.43	0.0007	
sep20	1	-629.4562	131.5977	-4.78	<.0001	

Model: MECO ELECTRIC INDUSTRIAL KWH, recon Method (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	27419.7334	DFE	220
MSE	124.63515	Root MSE	11.16401
SBC	1879.38698	AIC	1823.96568
MAE	8.29122583	AICC	1826.44969
MAPE	2.67250404	HQC	1846.30649
Durbin-Watson	1.9823	Transformed Regression R-Square	0.8252
		Total R-Square	0.8330

Parameter Estimates						
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	-7.9685	24.0756	-0.33	0.7410	
IDX_empl_manuf	1	1.6876	0.0729	23.16	<.0001	idx_EMPL_MANUF
cdd_5	1	0.1133	0.008355	13.56	<.0001	RevMo Cooling Degree Days, MECo
Bdays	1	4.1664	0.7456	5.59	<.0001	Number of Billing Days
mar08	1	-61.0761	11.2566	-5.43	<.0001	
apr08	1	49.0207	11.2259	4.37	<.0001	
nov08	1	-54.0017	11.1882	-4.83	<.0001	
jun14	1	-60.3447	11.1786	-5.40	<.0001	
aug14	1	42.7413	11.2259	3.81	0.0002	
sep14	1	-59.2898	11.2381	-5.28	<.0001	
oct14	1	41.3859	11.2186	3.69	0.0003	
nov14	1	41.1771	11.2055	3.67	0.0003	
jun13	1	-44.2642	11.1753	-3.96	0.0001	
dec21	1	70.0257	11.2556	6.22	<.0001	
jan22	1	-89.6465	11.2328	-7.98	<.0001	

Model: MECO ELECTRIC RESIDENTIAL CUSTOMER COUNT (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	2.15199E10	**DFE**	225
MSE	95644009	**Root MSE**	9780
SBC	5055.68606	**AIC**	5017.58391
MAE	7380.80339	**AICC**	5018.76248
MAPE	0.65190599	**HQC**	5032.94321
Durbin-Watson	2.1988	**Transformed Regression R-Square**	0.7501
		Total R-Square	0.9228

Parameter Estimates						
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	81785	43573	1.88	0.0618	
IDX_HHolds	1	10883	453.5117	24.00	<.0001	idx_HHOLDS
jul10	1	33458	8621	3.88	0.0001	
sep14	1	-31446	8623	-3.65	0.0003	
jan16	1	-29676	8623	-3.44	0.0007	
jun16	1	-24286	8624	-2.82	0.0053	
oct16	1	-32674	8623	-3.79	0.0002	
feb19	1	-45011	8624	-5.22	<.0001	
dec20	1	-45265	8624	-5.25	<.0001	
nov21	1	24081	8626	2.79	0.0057	

Model: MECO ELECTRIC COMMERICAL CUSTOMER COUNT (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	319440639	**DFE**	167
MSE	1912818	**Root MSE**	1383
SBC	3082.70942	**AIC**	3054.17506
MAE	1042.17441	**AICC**	3055.2594
MAPE	0.64313196	**HQC**	3065.74846
Durbin-Watson	2.2496	**Transformed Regression R-Square**	0.6820
		Total R-Square	0.8747

Parameter Estimates

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	3122	9151	0.34	0.7334	
IDX_HHolds	1	1632	93.9230	17.37	<.0001	idx_HHOLDS
jan16	1	-3713	1246	-2.98	0.0033	
oct16	1	-4161	1246	-3.34	0.0010	
dec16	1	-3320	1246	-2.66	0.0085	
feb19	1	-4396	1357	-3.24	0.0014	
mar19	1	2961	1357	2.18	0.0305	
dec20	1	-4895	1246	-3.93	0.0001	

Model: MECO ELECTRIC INDUSTRIAL CUSTOMER COUNT (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	522610.074	**DFE**	230
MSE	2272	**Root MSE**	47.66778
SBC	2522.16627	**AIC**	2501.38328
MAE	35.4073843	**AICC**	2501.75009
MAPE	0.82026262	**HQC**	2509.76108
Durbin-Watson	2.5258	**Transformed Regression R-Square**	0.4738
		Total R-Square	0.9888

Parameter Estimates						
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	1163	345.3625	3.37	0.0009	
IDX_empl_manuf	1	29.8790	3.1546	9.47	<.0001	idx_EMPL_MANUF
prerecession	1	162.5218	47.2059	3.44	0.0007	
dec08	1	-147.0555	35.2042	-4.18	<.0001	
feb19	1	-166.1933	35.2034	-4.72	<.0001	

APPENDIX B2: MODELS - Nantucket Electric

Model: NANT ELECTRIC RESIDENTIAL USE per CUST, recon Method (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	726204.836	DFE	226
MSE	3213	Root MSE	56.68594
SBC	2620.07101	AIC	2585.4327
MAE	42.2200543	AICC	2586.41047
MAPE	5.19719868	HQC	2599.3957
Durbin-Watson	1.8405	Transformed Regression R-Square	0.8878
		Total R-Square	0.9285

Parameter Estimates

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	-617.4719	118.8291	-5.20	<.0001	
IDX_PCI	1	7.7289	0.5926	13.04	<.0001	idx_PCI
hdd_season	1	-176.4283	17.2035	-10.26	<.0001	
cdd_season*cdd_4	1	3.0821	0.0906	34.01	<.0001	
hdd_season*hdd_4	1	0.3119	0.0240	13.01	<.0001	
Bdays	1	21.0310	3.5387	5.94	<.0001	Number of Billing Days
aug03	1	-123.8409	52.8251	-2.34	0.0199	
jul10	1	-201.9905	53.0318	-3.81	0.0002	
sep21	1	-169.5329	53.6464	-3.16	0.0018	

Model: NANT ELECTRIC COMMERCIAL USE per CUST, recon Method (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	19120951.4	DFE	223
MSE	85744	Root MSE	292.82107
SBC	3408.24952	AIC	3363.2197
MAE	217.736392	AICC	3364.85934
MAPE	6.52851326	HQC	3381.37161
Durbin-Watson	1.8735	Transformed Regression R-Square	0.7720
		Total R-Square	0.8241

Parameter Estimates

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	-101.1780	606.5648	-0.17	0.8677	
IDX_RPI_HH	1	7.9062	0.9966	7.93	<.0001	
cdd_4	1	7.6415	0.3956	19.32	<.0001	RevMo Cooling Degree Days, Nantucket
Bdays	1	49.6663	18.6993	2.66	0.0085	Number of Billing Days
sep04	1	1132	281.4894	4.02	<.0001	
aug06	1	-1629	296.9354	-5.48	<.0001	
sep06	1	1946	292.4831	6.65	<.0001	
mar17	1	-1114	292.4263	-3.81	0.0002	
apr17	1	1627	292.7919	5.56	<.0001	
sep17	1	1283	280.9011	4.57	<.0001	
feb20	1	1196	294.4561	4.06	<.0001	
mar20	1	-2075	293.6484	-7.06	<.0001	

Model: NANT ELECTRIC RESIDENTIAL CUSTOMER COUNT (Est.Period: Jan2008 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	99800.1602	DFE	158
MSE	631.64658	Root MSE	25.13258
SBC	1710.49434	AIC	1653.42563
MAE	18.6737251	AICC	1657.78232
MAPE	0.1599725	HQC	1676.57242
Durbin-Watson	1.5226	Transformed Regression R-Square	0.9829
		Total R-Square	0.9963

Parameter Estimates						
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	3163	555.1437	5.70	<.0001	
IDX_HHolds	1	90.2595	5.8803	15.35	<.0001	idx_HHOLDS
jun	1	22.8886	6.3106	3.63	0.0004	
jul	1	25.1090	8.1967	3.06	0.0026	
aug	1	30.3397	8.8915	3.41	0.0008	
sep	1	40.7329	8.9641	4.54	<.0001	
oct	1	47.4324	8.2287	5.76	<.0001	
nov	1	25.4108	6.4048	3.97	0.0001	
mar08	1	-108.5476	21.2044	-5.12	<.0001	
apr08	1	-135.0737	21.2044	-6.37	<.0001	
mar09	1	-50.9929	18.3780	-2.77	0.0062	
may10	1	-55.4700	18.6463	-2.97	0.0034	
jul10	1	170.1173	19.0229	8.94	<.0001	
feb14	1	-40.9006	18.3780	-2.23	0.0275	
apr16	1	112.8683	18.3781	6.14	<.0001	
feb20	1	-1704	18.3780	-92.73	<.0001	
jan21	1	-57.5265	18.3781	-3.13	0.0021	

Model: NANT ELECTRIC COMMERICAL CUSTOMER COUNT (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	15655.3553	**DFE**	226
MSE	69.27148	**Root MSE**	8.32295
SBC	1716.13313	**AIC**	1681.49482
MAE	6.50876582	**AICC**	1682.47259
MAPE	0.43519637	**HQC**	1695.45782
Durbin-Watson	2.1604	**Transformed Regression R-Square**	0.9535
		Total R-Square	0.9967

Parameter Estimates						
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	-604.7143	85.6570	-7.06	<.0001	
IDX_HHolds	1	22.9299	0.9341	24.55	<.0001	idx_HHOLDS
jun05	1	-47.3045	6.1453	-7.70	<.0001	
jan08	1	-26.6173	7.7424	-3.44	0.0007	
feb08	1	-66.4919	9.4573	-7.03	<.0001	
mar08	1	-124.7152	9.4573	-13.19	<.0001	
apr08	1	-26.2787	7.7424	-3.39	0.0008	
may16	1	-17.7347	6.1453	-2.89	0.0043	
feb20	1	-376.9208	6.1453	-61.34	<.0001	

APPENDIX C: Regression Statistics Discussion

All models are checked for overall goodness of fit, statistical validity and reasonable of results. In general, the following items are reviewed for each model.

1) Overall Goodness of Fit: Does the model adequately capture the explanatory aspects for the dependent variable? For example, for the residential use-per-customer model, do the explanatory economics, demographics, weather, calendar, and other independent variables adequately explain the monthly energy use. Several statistical tests can be used to gauge this. For this forecast, "Adjusted R-squared" is the primary test used. Values are expressed as a fraction of 1.0 and values closest to 1.0 are best. In theory, a 1.0 means that the variables being used explain 100% the energy use. For the most part residential models generally have Adjusted R-Squared values of 0.9 or higher, commercial models 0.85 or higher and industrial models 0.75 or better (based on past experience).

2) Correlation and Causality: Are the explanatory variables correlated with energy usage? That is, as a variable goes up or down, does the energy do the same? Are the variables causal? For example, can it be said that as summer weather gets hotter, would the expectation be that energy use would go up due to air conditioning and other cooling loads? For this forecast, correlation statistics are reviewed for correlation strength. Both general industry practice and experience are used to gauge causation.
3) Statistical Significance of Explanatory Variables: Are the independent variables statistically significant? P-values and T-statistics are used to determine this. Lower p-values indicate higher statistical significance. Generally, p-values less than or equal to 0.05 are considered statistically significant. However, in certain cases, explanatory variables with higher values (up to 0.10 or 0.15) may be useful to a model if that variable is known provide explanatory value.

4) Outliers and Influential Observations: There are times when several of the observations in the historical input dataset may be in error (ex: billing error) and have an undue influence on the outcome. An analysis of the residuals as well as statistical tests are used to determine this (statistical tests include R-Student and Cook's D). Outliers are corrected if possible or assigned a categorical 0 or 1 to exclude them from the model if they cannot be corrected.

5) Autocorrelation: Since energy usage is a time-series, the residuals may not be independent of time and can be autocorrelated, meaning the residuals can be correlated with prior observations of themselves, which can distort results. The Durbin-Watson statistic is used to test for autocorrelation (values of 2.0 indicate no influence, while values less than 1.6 or greater than 2.4 indicate possible autocorrelation). Autocorrelation is corrected with an autoregressive error model.

6) Additional Analysis: Additional analysis is done to ensure goodness of fit and the robustness of the model including a residual analysis, testing for heteroscedasticity, normality, and multicollinearity.

7) Reasonable Results: Is the resulting forecast reasonable? Is the forecast similar to historical trends? For example, if the residential customer counts have been growing annually at 0.5% per year over the last five years it would be expected, barring any significant changes in the economy or other explanatory variables, to continue to grow similarly over the next few years of the forecast. Major departures from historical trends require an explanation (for example a change in economic outlook or other factors.