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Part of the Avangrid family

2025
Distributed System Implementation Plan

New York State Electric & Gas and Rochester Gas and Electric

June 30, 2025

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List of Acronyms

AC - Alternating Current

ADMS - Advanced Distribution Management System

AGR - Automated Grid Recovery/Restoration

AMEEP - Affordable Multi-Family Energy Efficiency Program

AMI - Advanced Metering Infrastructure

ANM - Active Network Management

ASHPs - Air Source Heat Pumps

ATWG - Advanced Technologies Working Group

BCA - Benefit Cost Analysis

BESS - Battery Energy Storage System

BSS - Battery Storage System

BTM - Behind-the-Meter

CCA - Community Choice Aggregation

CDG - Community Distributed Generation

CESIR - Coordinated Electric System Interconnection Review

CGPP - Coordinated Grid Planning Process

CLCPA - Climate Leadership and Community Protection Act

CRM&B - Customer Relationship Management and Billing

DAC - Disadvantaged Communities

DAF - Data Access Framework

DC - Direct Current

DCFC - DC Fast Charging

DER - Distributed Energy Resource(s)

DERMS - Distributed Energy Resource Management System

DG - Distributed Generation

DMS – Data Management System

DPS - New York Department of Public Service

DR - Demand Response

DRV - Demand Reduction Value

DSASP - Demand Side Ancillary Services Program

DSIP - Distributed System Implementation Plan

DSO - Distribution System Operator

DSP – Distributed System Platform

EAP - Energy Assistance Program

ECC - Energy Control Center

EE - Energy Efficiency

EMS - Energy Management System

EPRI - Electric Power Research Institute

EPC – Engineering, Procurement and Construction

EPS - Electric Power System

ESC - Energy Smart Community or Energy Storage Coordination

ESCO - Energy Service Company

ESP - Electronic Security Perimeter

ESS - Energy Storage System

EV - Electric Vehicle(s)

EVSE - Electric Vehicle Supply Equipment

FERC - Federal Energy Regulatory Commission

FICS - Flexible Interconnect Capacity Solution

FLISR - Fault Location, Isolation, and Service Restoration

FPA - Federal Power Act

FTE - Full-time Equivalent

GBC - Green Button Connect

GHG - Greenhouse Gas

GIS - Geographic Information System

GMEP - Grid Model Enhancement Project

GSHPs - Ground Source Heat Pumps

HC - Hosting Capacity

HP - Heat Pump

HPWHs - Heat Pump Water Heaters

IEEE - Institute of Electrical and Electronics Engineers

IEDR - Integrated Energy Data Resource

IOAP - Interconnection Online Application Portal

IPV - Initial Public Version

IPWG - Interconnection Policy Working Group

ISP - Integrated System Planning

ITWG - Interconnection Technical Working Group

JMC - Joint Management Committee

LMI - Low- to and Moderate-Income

LSRV - Locational System Relief Value

LTC - Load Tap-Changers

M&C - Monitor and Control

MM&C – Measurement, Monitoring and Control

M&V - Measurement and Verification

MCOS - Marginal Cost of Service

MDMS - Meter Data Management System

MGMS - Microgrid Management System

NEM - Net Energy Metering

NYPA - New York Power Authority

NWA - Non-Wires Alternative(s)

NYISO - New York Independent System Operator

NYS - New York State

NYSEG - New York State Electric & Gas Corporation

NYSERDA - New York State Energy Research and Development Authority

NYSIR- New York State Standardized Interconnection Requirements

O&M - Operations and Maintenance

OMS - Outage Management System

OSG - Operational Smart Grid

PCC - Point of Common Coupling

PCIP - Participating Contractor and Industry Partner

PII - Personally Identifiable Information

PSP - Physical Security Perimeter

PSC - Public Service Commission

PV - Photovoltaic

REV - Reforming the Energy Vision

RFP - Request for Proposal

RG&E - Rochester Gas and Electric Corporation

RNM - Reference Network Model and Remote Net Metering

RTU - Remote Terminal Unit

SAP - System Analysis Program

SCADA - Supervisory Control and Data Acquisition

SEEPs - System Energy Efficiency Plans

SDLC - Software Development Life Cycle

SFTP - Secure File Transfer Protocol

SIR - Standardized Interconnection Requirements

SIWG - Smart Inverter Working Group

T&D - Transmission and Distribution

TOs - Transmission Owners

UCG - Utility Coordination Group

UDR - Utility Dispatch Rights

VAR - Volt-Amps Reactive

VDER - Value of Distributed Energy

VVO - Volt/VAR Optimization

WDS - Wholesale Distribution Service

WVS - Wholesale Value Stack

ZEV - Zero Emissions Vehicle

Executive Summary

New York State Electric and Gas Corporation ("NYSEG") and Rochester Gas and Electric Corporation ("RG&E" or collectively the "Companies") present their 2025 Distributed System Implementation Plan ("DSIP") Update following the framework provided by the New York State Public Service Commission's ("Commission" or "PSC") Reforming the Energy Vision ("REV") Proceeding[1] with further guidance[2] provided by the Commission. The Companies' DSIP responds to New York's clean energy goals as outlined in the 2019 Climate Leadership and Community Protection Act ("CLCPA") and further articulated in the 2022 Scoping Plan.[3] CLCPA establishes the following goals:

- 70% renewable electricity by 2030
- 100% zero-emission electricity by 2040
- Net zero emissions by 2050
- Transitioning to zero-emission vehicles
- Electrification of homes and commercial building space
- 10,000 MW of distributed solar by 2030
- 6,000 MW of energy storage by 2030
- 9,000 MW of offshore wind by 2035
- Ensuring the clean energy transition is a just transition

The Companies continue to play a fundamental role in helping the state achieve its goal of a clean energy transition by integrating clean, renewable energy, electrifying transportation and buildings, increasing energy efficiency, securely sharing system and energy usage data, and enabling access to electricity markets. As the Distribution System Operator ("DSO") for the Companies' service territories, the Companies will support the State in achieving these goals, provide customers with greater control over their energy usage, provide developers and other market participants information needed to make informed investment decisions and help the Companies maintain reliable and resilient electric service.

The 2025 DSIP Update describes the progress the Companies have made over the past two years to serve as the Distributed System Platform ("DSP") provider. This DSIP Update also

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[1] Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision

[2] Case 16-M-0411 – In the Matter of Distributed System Implementation Plans.

[3] New York State Climate Action Council, New York State Climate Action Council Scoping Plan (December 2022): https://climate.ny.gov/resources/scoping-plan/

provides detailed information regarding the Companies planned DSP investments over the five-year period ending in 2030 to allow for the integration of clean, renewable DERs.

In this DSIP Update the Companies:

- Present the Companies' vision for serving as the DSO.
- Describe the Companies' approach to building the technology platform required to serve as the DSO.
- Report on DSP actions and progress since the 2023 DSIP Update.
- Describe plans and actions to promote clean energy, enable greater levels of DERs, and achieve the State's clean energy goals.
- Identify and describe how the Companies engage with DER developers and other stakeholders and how the entities can access available tools and information to help them understand the Companies' electric system needs, and potential business opportunities.
- Provide useful links and citations to information so that stakeholders have access to the latest information.

Similar to previous DSIP Updates, the development of the Companies' 2025 DSIP Update was informed by a collaborative process with the Joint Utilities of New York,[4] Department of Public Service ("DPS") Staff, and numerous other stakeholders. This 2025 DSIP Update also incorporates feedback from Staff and DNV Energy Insights USA for NYSERDA ("DNV") in their assessment of the Companies' 2023 DSIP Update included in the First Iteration of the Grid of the Future Plan[5] filed in the Grid of the Future Proceeding,[6] and NorthStar Consulting Group's recent Management Audit.[7] DNV's overall assessment indicated a favorable view of the Companies' 2023 DSIP and five-year plan ahead. It also identified a

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[4] The Joint Utilities of New York are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Corporation d/b/a National Grid, Orange & Rockland Utilities, Inc., and Rochester Gas and Electric Corporation ("Joint Utilities").

[5] Case 24-E-0165 – Proceeding on Motion of the Commission Regarding the Grid of the Future, First Iteration of the Grid of the Future Plan, dated and filed March 31, 2025 and Notice Inviting Comments (issued April 15, 2025.

[6] 2025Case 24-E-0165 – Proceeding on Motion of the Commission Regarding the Grid of the Future, issued April 18, 2024.

[7] Case 23-M-0103 – A Comprehensive Management and Operations Audit of New York State Electric and Gas Corporation and Rochester Gas & Electric Corporation "A Comprehensive Management and Operations Audit of New York State Electric & Gas Corporation and Rochester Gas & Electric Corporation" to the Department of Public Service staff (Staff) dated February 4, 2025 and issued in the Order Releasing Audit Report (issued and effective May 19, 2025).

few areas for improvement, including the need for the Companies to more thoroughly explain the Companies' stakeholder engagement and implementation plans & schedules, to ensure that the 2023 DSIP followed the intent of DPS guidance.

In this 2025 DSIP Update, the Companies provide robust details documenting improvements in these areas since the 2023 DSIP along with plans to further advance electrification, the integration of DERs, and engagement with stakeholders. All of the plans over the next five years are aligned with the Companies' 2025 rate case proposals and Management Action Plans in response to the recent Management Audit Recommendations.

1. Progressing the Distributed System Platform

1.1 Our Vision: Enabling a Reliable and Flexible Grid

Since the outset of the REV proceeding, the Companies' approach has been twofold: (1) to incorporate and optimize the use of DERs into utility planning and operations to provide safe, reliable, and efficient electric services, and (2) to facilitate the distributed energy marketplace through a DSP which empowers communities and customers, promotes affordability, and supports the State's clean energy policy goals. The Companies' vision is to serve as a DSO, which is an organization that assumes the roles and responsibilities consistent with the DSP initially contemplated in the REV proceeding, enabling a reliable and flexible grid to help achieve a new energy future. In addition to the traditional electric utility responsibilities of providing safe, reliable electric service to customers, the DSO helps the utility serve an increasingly diverse customer group, including energy consumers, producers, "prosumers," and aggregators.

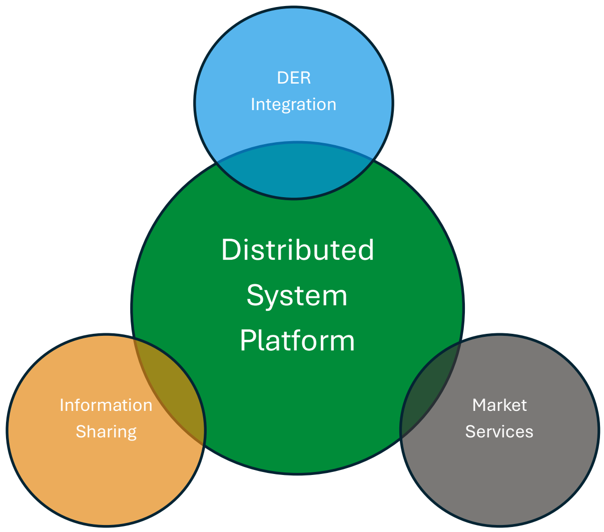
DSO Roles and Responsibilities

- Plan and develop the electric distribution system to accommodate clean DERs and beneficial electrification.
- Operate the electric distribution system safely, reliably, and efficiently, while utilizing the capabilities of DERs.
- Enable customer access to energy services and markets to increase the value of investments in an integrated electricity infrastructure.

The Companies' previous DSIP filings have documented both foundational investments and advances in means and methods that have enabled considerable progress toward that vision. This DSIP Update continues that consistent vision for the future, while beginning to add focus on how those investments and advances unlock innovation and investment to maximize the benefits of flexible resources.

The Companies continue to organize efforts through what has long been defined as the three core DSP functions: DER Integration, Market Services, and Information Sharing [Exhibit 1.1-1].

EXHIBIT 1.1.1-1: DSP FUNCTIONS: DER INTEGRATION, MARKET SERVICES, AND INFORMATION SHARING



1.2 Regulatory Background

The set of regulatory initiatives and state policy goals driving the development of the DSP have evolved over the past ten years. The Commission defined the initial set of DSP-related objectives in its REV Track I Order in April 2014[8]. The six core REV goals were:

1) **Enhance Customer Knowledge and Tools to Support Management of Energy Bills**
2) **Animate the Marketplace and Leveraging of Ratepayer Contributions**
3) **Improve System-Wide Efficiency**
4) **Increase Fuel and Resource Diversity**
5) **Enhance System Reliability and Resiliency**
6) **Reduce Carbon Emissions**

Subsequent laws and regulatory initiatives built upon those goals. The Clean Energy Standard (CES) established a goal of achieving 50% clean energy by 2030 [9] (later revised

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[8] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Instituting Proceeding (issued April 25, 2014).
[9] Case 15-E-0302 – Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard.

upward to 70%) and was followed by the 2019 CLCPA which expanded upon state climate goals[10]. In the case of the CLCPA, those expanded goals included:

- **85% reduction in GHG Emissions by 2050**
- **100% carbon-free electricity by 2040**
- **10,000 MW of distributed solar generation**
- **6,000 MW of energy storage**

The PSC's introduction of the Coordinated Grid Planning Process ("CGPP") in 2021 supported the original REV goal of improving system-wide efficiency by increasing coordination between bulk power system planning and generation interconnection and increasing integration of Local Transmission and Distribution ("T&D") studies with NYSERDA's renewable generation and storage procurements.[11]

Several regulatory initiatives in recent years also continued to build on the original REV goals of enhancing fuel and resource diversity and abating carbon emissions by focusing on electrification. As a result, the 2023 utility DSIPs placed a greater emphasis on electrification and identification of enabling investments and programs.

1.3 Utility Foundational DSP Investments Have Enabled Significant Progress Toward New York's Policy Goals

Utility efforts, both individually and coordinated through the Joint Utilities of New York (JU), have been essential in enabling DSP functions and securing significant advances toward the original six goals. Topics being addressed by the JU include coordinated grid planning, advanced technologies, interconnection of DERs, energy storage, electric vehicles, hosting capacity, the Integrated Energy Data Resource ("IEDR"), and energy efficiency. Working collaboratively with DPS and the New York State Energy Research and Development Authority ("NYSERDA"), and with robust engagement and feedback from stakeholders, we have been able to advance DSP functions and implement programs that have brought us closer to our long-term vision.

The Companies continue building the platform to enable the DSO. As included in the Companies 2023 DSIP, the Companies infrastructure deployment is organized into six

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[10] Case 15-E-0302. 0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard. Order Adopting Modifications to the Clean Energy Standard. (issued April 18, 2024).
[11] Case 20-E-0197. Initial Coordinated Grid Planning Process Proposal.

"technology initiatives." Specific investments to advance the technology initiatives are presented in the topical section. The six technology initiatives are presented and described below.

Advanced Metering Infrastructure ➢ Customer data and billing ➢ Analytics ➢ Outage notification ➢ Grid automation	Advanced meters plus communications infrastructure provide granular customer consumption data that (a) can be used to develop granular load profiles and forecasts, (b) help customers manage their energy usage, and (c) provide grid operators with grid-edge visibility and advanced operational capabilities.
Grid Automation and Management ➢ Control center systems and grid optimization ➢ Grid automation ➢ DER management	Automated grid devices and management technologies that provide the Energy Control Center ("ECC") with visibility and decision support to adjust the distribution system to support resiliency, reliability, power quality, DER integration, and other outcomes and, with the implementation of an Advanced Distribution Management System ("ADMS"), optimize grid assets and DERs.
Integrated System Planning ➢ Advanced forecasting ➢ Non-wires alternatives (NWAs) and beneficial locations ➢ Hosting capacity ➢ Interconnections	A holistic and inclusive planning process that reduces cost, improves efficiency, and achieves societal clean energy targets.
Data and Analytics ➢ Integrated Energy Data Resource (IEDR) ➢ Grid Model Enhancement Project (GMEP)	(a) Internal integrated network system models of grid assets and connected DERs for sharing externally, (b) mechanisms to securely share system and customer data to external platforms, (c) advanced analytics use cases to improve system operations and preemptively address infrastructure issues, and (d) analytics that improve our customer experience.
Clean Energy and Decarbonization ➢ Electric vehicles ➢ Energy storage ➢ Clean heat and building electrification ➢ Energy efficiency ➢ Smart inverters	Investing in grid infrastructure that will increase deployment of renewables, clean DERs, and beneficial electrification to enable a new energy future and meet State clean energy and decarbonization goals.
Market Services and Innovative Customer Offerings ➢ Billing system automation and compensation ➢ DER aggregation for market access ➢ Rate design	Connect customers to pricing options and programs, as well as to products and services offered by competitive suppliers; implementing incentive programs that support market transformation.

The Companies continue to deploy Advanced Metering Infrastructure ("AMI") and grid automation investments. Additionally, to further support Integrated System Planning, the Companies continue building a validated repository of electric system assets through the execution of the GMEP.

Utility actions have contributed significantly to electrification, and especially to advancing New York's EV marketplace, especially through electric vehicle-related proceedings such as the DCFC Per Plug Incentive Program, EV Make-Ready Program, EV Residential Managed Charging Program, Load Management Technologies Incentive Program, Demand Charge Rebate, EV Phase-in Rate, Commercial Managed Charging Program, and Medium- and Heavy-Duty Make-Ready Program.

In addition, the NYS Clean Heat Program, which launched on April 1, 2020, provides customers, contractors, and other heat pump solution providers with consistent experience and business environment throughout New York State. The utilities have participated in implementing a common statewide framework to advance the adoption of heat pump systems.

The results of regulatory vision, state incentive support, stakeholder participation, and utility DSP enablement and program implementation have been encouraging. As described by DPS[12]:

- The solar industry has grown from 325 megawatts (MW) of installed capacity in 2014 to approximately 4.3 gigawatts (GW) as of March 2024.
- There have been approximately 1.0 GW of deployments, awards, and contracts for storage as of March 2024.
- There have been nearly 59,000 heat pump installations through 2023, representing over 4.5 trillion British thermal units (TBtu) of annual energy savings.
- Nearly 210,000 EVs have been registered in New York as of March 2024, and the Commission authorized EV Make-Ready program has supported approximately 20,000 level 2 charging stations and approximately 1,500 direct current fast charging stations either completed or in the process of being constructed as of March 2024.
- Approximately 1,375 MW of demand response capability were enrolled in the Commission directed utility programs in 2023.

Therefore, New York has seen notable advances in all six original REV goals. The JU individually and collectively through the IEDR, greatly **enhanced customer knowledge** and

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[12] Case 24-E-0165, Proceeding on Motion of the Commission Regarding the Grid of the Future, Order Instituting Proceeding (issued April 18, 2024).

implemented programs that give customers more tools to control their bills. The profusion of DERs show that New York has **animated the market** for advanced technologies and services. Enhanced planning across the T&D systems is **improving system wide efficiency**. The success of the Clean Heat and EV programs is **increasing fuel resource diversity**. The penetration of storage and DSP-enabling grid management technologies like ADMS and a Distributed Energy Resource Management System ("DERMS") **enhance system reliability and resiliency.** And the growth of electrification and DERs are **reducing carbon emissions**.

In summary, over the past ten years, the Companies have made significant progress in developing and enabling the DSP, and in tandem with our regulatory and market partners, have advanced toward our vision for enabling New York's new energy future.

1.4 Developments Since the 2023 DSIP Have Added a Focus on Flexibility

In April 2024, the Commission initiated the Grid of the Future proceeding.[13] The objective of the Grid of the Future ("GOF") proceeding, as described in the Instituting Order, is "to unlock innovation and investment to deploy flexible resources—such as distributed energy resources (DERs) and virtual power plants (VPPs)—to achieve the state's clean energy goals at a manageable cost and at the highest levels of reliability."

The goals of the GOF proceeding are clearly aligned both with the DSP enablement that the Companies have achieved so far and with their longstanding vision. They build on the original six REV goals with a particular emphasis on long-term system efficiency.

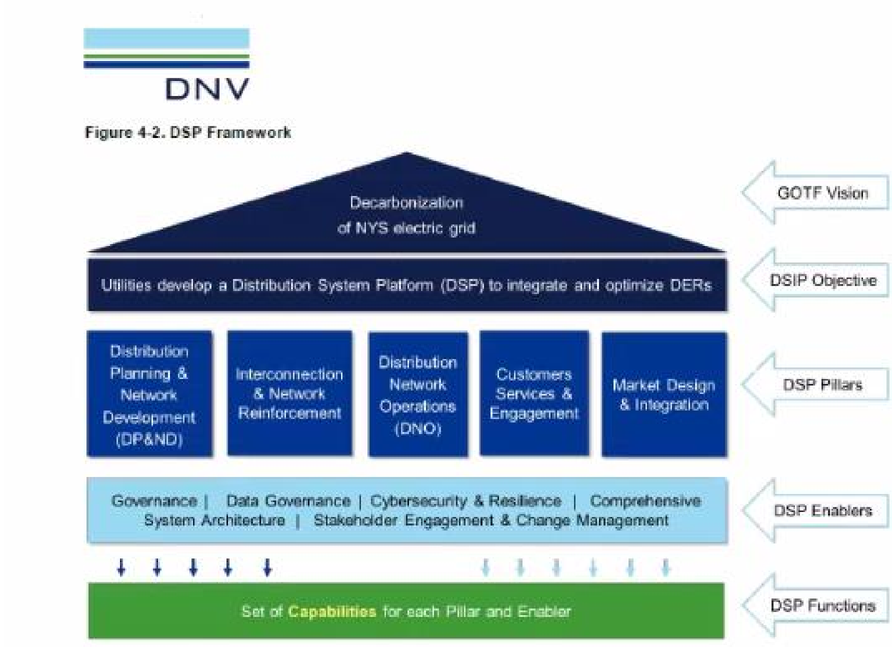
The vision for the continued development of the DSP under the GOF proceeding also builds directly on the longstanding core functions of the DSP that the utilities have long used. In its First Iteration of the Grid of the Future Plan, DPS and NYSERDA introduced a potential DSP framework built around "five pillars" — Distribution Planning & Network Development (DP&ND), Interconnection & Network Reinforcement, Distribution Network Operations (DNO), Customer Services & Engagement, and Market Design & Integration [Exhibit 1.4-1].

These "five pillars" are closely aligned to the "three core DSP functions" around which the JU has been organizing, with the new "five pillars" framework parsing out interconnection and adding more focus on operations. While we continue to use the three core functions

[13] Case 24-E-0165, Proceeding on Motion of the Commission Regarding the Grid of the Future, Order instituting Proceeding (issued April 18).

framework in this DSIP, we look forward to evolving the framework as needed in future DSIPs.

EXHIBIT 1.4-1: DSP FRAMEWORK



1.5 Priorities Aligned to the 2025 DSIP

Looking forward, our vision for the future remains consistent while incorporating an added focus of leveraging DSP capabilities to enable deployment of flexible resources to achieve State policy goals. As the State emphasizes increased grid flexibility, our ongoing investments in grid technologies, advanced planning, and grid operations methods will continue to empower communities and customers to actively manage their energy needs and participate in the marketplace in support of the State's policy goals.

To best align further progress in support of the GOF objectives, we recognize that there will be significant barriers to overcome to achieve flexibility at scale, as identified in the Grid of the Future Phase 1 Grid Flexibility Study.[14] We plan to work closely with DPS and stakeholders to identify solutions for overcoming the barriers, to develop metrics toward enabling greater flexibility, and to consider the appropriate set of incentives for all market participants.

The First Iteration of the Grid of the Future Plan also introduces an emphasis on future DSIP filings developing a more explicit vision for Comprehensive System Architecture (CSA), which it defines as being comprised of three interlocking elements[15]:

- **Electric Infrastructure** includes the physical grid resources that meet the operational needs of grid operators, grid service providers, utility business managers, and customers to implement DSP capabilities (DER integration, grid control and monitoring, etc.).
- **Digital Infrastructure** includes both the business information systems (IT) and operations management systems (OT) that enable the utility to implement and advance essential DSP capabilities (i.e., market operations, DER integration, and flexible grid operations).
- The **Commercial Framework** includes an integrated set of standards that are applied to design, implement, and operate the commercial mechanisms that enable the utility's business and grid operations.

While this DSIP does not explicitly address a long-term CSA vision, the Companies and the rest of the JU have been active participants in proceedings like Market Design and Implementation that have considered future grid architecture models, and the best potential set of solutions for New York. As consultations with stakeholders proceed through the Grid of the Future proceeding, we look forward to incorporating more discussion on CSA in future DSIPs.

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[14] Case 24-E-0165, Proceeding on Motion of the Commission Regarding the Grid of the Future, Grid Flexibility Study Phase 1 Final Report Vol. 1 – Summary Report

[15] Case 24-E-0165, Proceeding on Motion of the Commission Regarding the Grid of the Future, Grid of the Future Plan-First Iteration

2. Topical Sections

2.1 Integrated Planning

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2023 DSIP Update filing.

The clean energy paradigm, technology advancement, and the need for increased stakeholder involvement are rapidly changing utility planning requirements. To meet these changing requirements the Companies are focused on expanding planning processes and capabilities and adopting a more integrated approach to planning. The integrated system planning ("ISP") initiative aims to incorporate processes and technologies to ensure reliable, safe, and efficient planning and design of the distribution network, while providing customers and third parties ease of interconnection. We are integrating DERs into our long-term planning processes, optimizing the contribution of DERs together with our more traditional investments that we make to improve the reliability and resiliency of the grid. The ISP initiative aims to address processes and technologies needed through stakeholder engagement, development of advanced forecasting and advanced system modeling, and identification of ("T&D") solutions.

The Companies' ISP initiative capabilities include

1. **Advanced Forecasting**

   Advanced forecasting refers to the capability to produce load and DER forecasts by location and hour of the year. Advanced forecasting will support integrated system planning and grid operations and will enable DER developers to make informed investment decisions. The granular forecasts will provide system planners with long-term forecasts of load and DERs by location and time thereby improving investment decisions to continue to provide safe, reliable, and resilient service. The forecasts will also reflect electrification trends and state policy goals. Forecasts must be sufficiently granular with respect to location (*e.g.*, by feeder) and hour of the year (i.e. 8760 hourly forecasts) to support the integration and optimization of connected DERs. These forecasts also will support the evaluation of utility programs and tariffs intended to incent efficient investment and electricity usage decisions. The Companies are also developing short-term forecasts for operational planning purposes to support active network management ("ANM"), resource curtailments, and potential probabilistic use case scenarios.

2. NWAs and Beneficial Locations

NWAs and beneficial locations refer to the process of identifying locations with potential for localized DERs deployment to address projected system growth or capacity needs, and procuring NWAs intended to make lower-cost investments in grid infrastructure by deferring or avoiding traditional infrastructure investments in “wires” solutions. NWAs benefit NYSEG and Rochester Gas and Electric and their customers, as NWAs replace or defer traditional “wires” projects with DERs and other market-based solutions, potentially provide cost savings, and deliver environmental benefits, while maintaining system reliability and resiliency.

3. Hosting Capacity

DER Hosting capacity refers to an estimate of the amount of DERs that can be accommodated without compromising the power grid. New York’s investor-owned electric utilities publish maps that show the estimated amount of hosting capacity along each distribution circuit. DER developers can use these maps to efficiently target their marketing efforts to areas where DERs are likely to require minimal investment in grid upgrades. The Companies’ hosting capacity advances focus on streamlining incoming data from the field to enable more accurate information, supported through rapid data refreshes and accurate data and process automation to reduce the required manual processes. Over the longer term, the Companies’ hosting capacity maps may also reflect the impact of severe weather or other hazards on DERs and the resulting influence on hosting capacity to include contingency plans, DER service level agreements, reliability metrics, and assessment of DERs value to support grid reliability and resiliency.

4. Interconnections

Since the 2023 DSIP filing, NYSEG and RG&E have continued to process interconnecting DERs within the required timelines specified in the New York State Standardized Interconnection Requirements (“NYSSIR”). This is further described in Topical Section 2.11, regarding DER Interconnections.

5. The CGPP

The CGPP is a cyclical study process developed by the Joint Utilities to identify upgrades to the T&D networks required to support meeting the CLCPA renewable generation integration and decarbonization goals. The CGPP framework was originally filed on December 17, 2021. The process was refined through technical conferences and stakeholder engagement to the updated CGPP Proposal of January 5, 2023. This updated proposal was accepted, with modification, by the Commission on August 17, 2023, and work began on the CGPP in Q1 of 2024. The first cycle of the CGPP is planned to be completed in Q2 of 2026. Much of the work completed as part of this Integrated System Planning effort can be leveraged within the CGPP. Concepts like Advanced Forecasting, NWAs and Beneficial Locations, Hosting Capacity, and Interconnection assumptions will be key input assumptions into the CGPP. Similarly, the capacity expansion modeling that will be done during the CGPP can give insights to future renewable build-outs that can inform the DSIP and its effects on forecasting, hosting capacity, and interconnections. In addition, the capital investments identified through the CGPP to unlock renewables will also be important to the DSIP as these improvements could potentially increase hosting capacity on the distribution system.

Current Progress: Describe the current implementation as of June 30, 2025, describe how the current implementation supports stakeholders' current and future needs.

Our current focus is to build a strong foundation to integrate large quantities of DERs into our ISP and Grid Operations functions, as well as developing the capabilities to automate processes and provide data accuracy to reflect real-time grid conditions. Both our Integrated Planning and Grid Operations functions require the ability to collect, update, maintain, manage, and access granular data. This capability depends, in turn, on infrastructure investments that collect data on customer loads at meter points AMI and power flows and attributes (e.g., voltage) throughout the network (sensors and other intelligent grid devices). With respect to Integrated Planning, we are also focused on building capabilities that will leverage more granular data while sharing the results of these enhanced analyses with DER developers to support their marketing, project development, and interconnection efforts. The Companies are making progress in automating interconnection and hosting capacity processes, and applying lessons learned from NWA projects and solicitations.

Advanced Forecasting: Avangrid's Data Science team has successfully developed an SQL database specifically designed to support granular load forecasting efforts. This database includes monthly billing data for every customer, EV registration data, EV charging infrastructure data, and heat pump customer data, all mapped to individual distribution feeders to enhance forecast precision. This comprehensive database will play a critical role in informing future bottom-up forecasting models. In addition to these efforts, the team is actively collaborating with vendors to acquire additional customer segmentation and load research data that could further refine and improve bottom-up forecasting models. The team is engaged with the internal customer service and digital experience team to leverage their interactions with customers to get more customer segmentation and appliance type. These efforts combined will yield a more comprehensive understanding of consumer behavior and will better inform bottom-up forecasting models.

The Companies are leveraging multiple data sources to build a robust load research database, including surveys, Department of Motor Vehicle (DMV) records, heat pump rebate information, and vendor-provided data such as appliance insights from Experian. These initiatives aim to capture detailed heating and cooling appliance inventories by customer, enabling the creation of more accurate feeder-level load forecasts that reflect localized adoption trends and appliance saturation rates.

As the AMI project progresses, the Companies are working diligently to access and utilize AMI data, with some progress already made into leveraging AMI and Supervisory Control and Data Acquisition ("SCADA")/sensor data stored in the Companies' data lake. These efforts are laying the groundwork for a granular load forecasting pilot project, funded under Case 22-E-0317, et al., which is expected to begin in July of this year. This integration of AMI and SCADA data is expected to provide valuable insights into system operations and enhance forecasting granularity and accuracy. In parallel, preparations are underway to launch the advanced load forecasting pilot project that will test advanced software capable of integrating AMI, SCADA, and DER/EV/HP data to generate long-term, time-series (8,760-hour) forecasts at the distribution feeder level. This software, proposed as part of the Companies' next planned rate filing, aims to address gaps in SCADA data by leveraging AMI data, and vice versa, thereby enhancing bottom-up forecasts. Designed for seamless compatibility, the software will integrate easily with existing forecasting tools and other databases used by the load forecasting team, providing a solid foundation for more accurate, localized forecasts and improved capacity planning. Additionally, the impact of EVs and HPs on peak load by distribution substation has been assessed using Bass-Diffusion modeling for adoption curves and the NREL Pro-Lite tool for estimating peak demand. Registration data for EVs was gathered from NY DMV. While information for HPs has been more challenging to obtain, the Companies have had some success with identifying HP conversions through NYSERDA rebates. This approach has provided greater visibility into areas with high adoption rates and enhanced system insight into future needs.

<u>NWAs and Beneficial Locations</u>: The Companies procure NWAs through a competitive solicitation process and identify locations on the grid where DERs could help address

constraints and potentially defer grid investments or where other electrification load can be accommodated. After applying lessons learned from earlier NWA development and contract negotiations, the Companies developed a standard NWA contract to streamline the advancement of future NWA opportunities. The Companies have also implemented monitoring and verification processes and continue to apply marginal cost of service ("MCOS") and value of distributed energy resources ("VDER") methodologies. In 2023, NYSEG commissioned its first NWA project in the Village of Stillwater. In 2024 the Companies identified multiple opportunities for additional NWA solutions. These include projects in Lancaster and the Liberty Area which have requests for proposals scheduled to go out in 2025. In 2027, the Companies plan to revisit the Java Microgrid Project. The Java microgrid backup supply power project schedule will be evaluated in 2026 for a solicitation in 2027. The Java peak shaving project was previously put on hold due to lower loading levels resulting from circuit conversions/transfers to neighboring circuits.

Hosting Capacity: Since 2020, the Companies have developed hosting capacity maps. Following updates since the initial implementation, the current iteration of the Companies' Hosting Capacity Maps have three layers: (1) Photovoltaic ("PV") Hosting Capacity, which considers the minimum and maximum loads on feeders to determine hosting capacity; (2) Electrification Capacity; and (3) BESS, which can increase hosting capacity on a circuit when coupled with DERs. These updates were completed as part of Stage 3.5 of Joint Utilities' Hosting Capacity("HC") roadmap. The hosting capacity maps began with feeder-level data. PV HC maps have since been upgraded to provide section-level data as of the last DSIP update while upgrading storage maps to section-level data is underway. Section-level data looks at the max of each attribute (defined by the JU) and selects the min of the max attributes. The PV HC map currently does not include the impact of queued DER assets. However, it mentions how much DG is queued on each feeder and substation. The detailed list of all queued DERs is available on NYSEG and RG&E's interconnections website[16,17] . The Companies also made CYME upgrades to interface with various systems. The Joint Utilities are currently in discussions to update both PV and battery energy storage systems ("BESS") maps on a yearly basis at the same time.

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[16] RG&E: https://www.rge.com/documents/40137/2123513/RGE+Project+Queue+Order+by+Substation_03.15.23.pdf/3c323909-47c4-5755-ab4c-52cc44a24023?t=1678885923511

[17] NYSEG: https://www.nyseg.com/documents/40132/5899056/NYSEG+Project+Queue+Order+by+Substation_03.15.23.pdf/16da38d5-f4ba-4bb6-d819-dc18c434ea53?t=1678886286162

Interconnections: NYSEG added one additional internal resource as well as two contractors to provide a better developer experience. Additional support will help in the CESIR reporting efforts, as well as bringing projects to fruition. The process includes Company personnel who collaborate with developers as they navigate through the interconnection process. The following are some efforts provided to developers: ad hoc/set scheduled meetings to discuss next steps in the process, provide guidance, and review independent construction schedules so Company and developer's timelines come together for inspection, energization, and testing after construction is complete. It is important that the Companies consistently communicate work efforts with developers to ensure projected completion date(s), to manage external stakeholder expectations and to forecast accurately. NYSEG proposes to add two Senior Analysts and one Manager – Programs/Projects in the Companies' next planned rate filing These additional Full-time Equivalent ("FTEs") will enable the Company to manage the increasing volume of applications and projects moving into execution.

The Companies also participate in the Joint Utilities' Interconnection Technical Working Group ("ITWG") and Interconnection Policy Working Group ("IPWG"), and have made considerable progress in the following areas:

Coordinated Electric System Interconnection Review ("CESIR") Study Process Reexamination: The JU collaborated with members of Industry on a "Comprehensive CESIR Analysis Evaluation Initiative" to help developers better understand how interconnection applications are being studied in the CESIR process. The JU provided detailed responses to Industry on study methods for certain screens within the CESIR: Overvoltage, Undervoltage, Voltage Regulator Correction Capability on Feeders and Substations, Excessive Regulator Movements, and Voltage Flicker. This initiative led to the JU providing detailed data publicly on the number of new DER projects passing or failing the CESIR process on an annual basis, as well as a re-examination of the voltage flicker calculation (CESIR Screen H).

As mentioned previously, the JU collaborated with EPRI, Pterra Consulting and Industry to amend the voltage flicker calculation (Screen H) in the CESIR. This amendment went into effect on April 1, 2022. The amendment is anticipated to result in an increase in projects passing the CESIR Screen H.

Storage Metering Guidelines: The JU developed and proposed storage metering architectures for various technology configurations (storage exclusively charged by DG, storage unable to export to the grid, any charging and exporting configuration with netting) to serve as a guide for developers. The goal of the publication of this document was to give developers a better sense of the metering configurations that could be used for their projects.

Grounding Practices: The JU collaborated with EPRI to make noteworthy progress on understanding effective grounding practices and policies for DERs. The effort helped inform and improve the JU's interconnection study capabilities and safety measures. The collaboration also resulted in the publication of a report, thus contributing and adding to the existing body of knowledge on this topic.

Voltage Regulation: The JU created a joint "Voltage Regulator Subgroup" with Industry to help stakeholders better understand how pole-mounted regulator tap operations are affected by PV interconnection, which in turn has implications for CESIR study screens and regulator lifetimes. As part of this initiative, the subgroup surveyed commercially available regulators and utility data to understand regulator lifetimes and the number of possible tap movements in the presence of DERs.

Bulk Power System Support and Smart Inverter Settings: The JU developed and released bulk power system support and voltage support settings/ setpoints for smart inverters, as part of the Phase 1 activity of Companies' joint Smart Inverter Roadmap. The release of these settings was timed to align with the commercial availability of Institute of Electrical and Electronics Engineers ("IEEE") 1547-2018 compliant and UL 1741- SB certified inverters. To develop the settings, the JU collaborated extensively with New York Independent System Operator ("NYISO"), peer utilities, and members of industry. Consequently, the JU members incorporated the inverter setpoints into their respective technical interconnection documents. The JU also provided DPS and Industry with a document containing web links to each company's documentation. The JU also created a smart inverter FAQ document for non – technical audiences. In collaboration with the IPWG, DPS, and Industry, the JU updated the SIR document to reflect the outcomes of ongoing discussions, including items related to the use of smart inverters.

DER Technical Guidance: The JU updated the DER technical guidance/ requirement matrix and the cost matrix to provide up to date information for developers. Both matrices provide indicative estimates of various scopes of work and the relevant costs associated with the interconnection of DERs on an individual company basis.

Inverter Settings: In collaboration with the Electric Power Research Institute ("EPRI") and Industry, the JU is currently investigating the implementation and enforcement of a standard file settings format to share inverter settings. EPRI demonstrated the details of the inverter settings sharing format with the ITWG, as well as separately to the JU. Using this file format will create consistency and standard approaches to inverter settings file creation, verification, and implementation. As a result of this collaboration the JU have engaged EPRI to aid in developing standard inverter settings files for each individual utility within the JU.

As mentioned previously, the JU have made considerable progress in the following areas:

Incorporating smart inverters, which offer the benefit of several advanced functions and could potentially be used as a low – cost monitoring and control solution.

Additionally, the use of standardized file sharing formats such as the EPRI CFF is anticipated to reduce the time required for utility engineers to study inverter settings, which will in turn improve interconnection application processing times.

Extending the timeline for requirement of UL 1741 SB certified bi-directional EV chargers, thus staying aware of certification timelines, and demonstrating collaboration with EVSE manufacturers.

Through the UL 1741 CRD for Multimode effort, remaining cognizant of technical standard development activities and new DER architectures.

Making edits to the SIR, which is anticipated to lead to a greater volume of interconnected DERs.

Establishing the storage charge and discharge schedules, which will help developers maximize the economic value that BESS assets can accrue.

Providing developers with the latest information via refreshes of the interconnection cost matrices.

Providing developers visibility and transparency into utility processes for estimating and reconciling the costs of distribution system upgrades identified in CESIR studies.

These implementation efforts support stakeholder needs and state clean energy goals by resulting in increased efficiency in the interconnection application and study processes, which in turn result in increased volumes of DER interconnections.

These implementation efforts support stakeholder needs and state clean energy goals by resulting in increased efficiency in the interconnection application and study processes, which in turn result in increased volumes of DER interconnections. The development of low-cost monitoring and control solutions for DER results in economic benefits to developers.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2030, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2030 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation; Described where and how plans for topic-related work and investments affect the CGPP; Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

Integrated Planning Functions

The Companies' priorities for the next few years (through 2025) include designing the data foundation to support Integrated Planning and Grid Operations and integration of storage, other DERs, and EV charging stations.

Advanced Forecasting: Once the previously mentioned advanced load forecasting pilot is completed and working successfully, the Companies will look to implement the pilot application (Metrix IDR) on a companywide level. The Companies have researched solutions that leverage AMI, DER, SCADA, electrification adoption, and customer segmentation data to inform and create distribution substation/circuit-level time-series forecasting. The Advanced Load Forecasting effort is designed to improve the granularity of load forecasting, including electric vehicle (EV), Heat Pump (HP), and DER adoption in terms of time, location, and impact on the distribution system. The project would allow for the development of models that assess adoption and load impact from EVs, electric heat pumps, and other related market trends. Additionally, impacts of different variables like rate design, managed charging programs, and other factors that might alter load shapes can also be simulated. Using an Advanced Load Forecasting tool, distribution system planners can address both short-term circuit trends and long-term grid expansion needs while remaining consistent with the overall corporate load forecasts for energy and peak demand. This tool will enable planners to analyze specific future scenarios/simulations such as high/low solar penetration, electric vehicle, and heat pump adoption. This will better inform the Companies' capacity and proactive planning efforts as well as address the forecasting priorities outlined in New York's DSIP efforts under the REV proceeding.

Because the Companies currently utilize ITRON's MetrixND forecasting software for both their sales and peak load forecasting processes, it was reasonable to research advanced analytical applications that would work synergistically with MetrixND. ITRON provides a granular forecasting application, called MetrixIDR, that pairs with the MetrixND software but also ingests AMI and SCADA data, and a host of other data streams, to produce long-term time series forecasts at the distribution feeder level. Additionally, the MetrixIDR software allows for multiple simulation scenarios to be run for each circuit, such as various levels of DER or EV or HP adoption and produce reports on each with its interactive dashboards. With the MetrixIDR software application, the Companies would be able to produce long-term hourly load forecasts on every distribution circuit that could then be aggregated up to a corporate level hourly load forecast. This approach would allow for more robust time series (i.e., hourly) analysis to better inform system planning efforts, more optimally align possible Non-Wires Solutions (NWS), and significantly improve visibility of the grid. Additionally, this proposed Advanced Load Forecasting approach would allow the Companies to comply with several of the DSIP priorities.

Creating robust granular load forecasts that leverage AMI and SCADA insights requires significant amounts of data, segmented information on customers, electrification adoption trends and the ability to effectively manage and utilize these large datasets. To support this effort the Companies have created a dedicated Load Research and Analytics team that will oversee the collection and compilation of these types of data and associated analysis. Resources to support this undertaking were included in the recent management audit recommendation action plan and will be included in the Companies' next planned rate filing.

NWAs and Beneficial Locations: To further scale NWA solicitations and project implementation, the Companies have taken steps to align internal processes (e.g., ISP processes) to identify NWA opportunities earlier on in planning process, with a focus on projects that fulfill CLCPA targets including providing consideration to Disadvantaged Communities ("DACs"). Over the near term, the Companies will continue to refine monitoring and verification protocols and make iterative improvements to the NWA contract administration and incorporate granular AMI and system data into NWA analyses. The Companies will also administer the Stillwater contract and leverage lessons learned from Stillwater to help with the deployment of additional NWA projects. The Java Microgrid project in 2027 will help to inform future projects and establish requirements for NYSEG-ownership and operation of DER assets. Over the long term, with GMEP and other technologies in place to perform more frequent system studies, the Companies will develop planning processes to identify beneficial locations and VDER stack planning processes.

In 2023, the Companies developed a New York Non-Wires Alternatives Opportunity Identification and Scoping Process. The guide's objective is to furnish readers with an understanding of the essential elements to be considered when evaluating electric infrastructure needs and exploring optimal solutions. This guide helped to identify an NWA for Ferndale Substation and provides steps for prioritizing potential NWA solutions within the portfolio.

Hosting Capacity: The Joint Utilities are now in Stage 4.0 of the Hosting Capacity roadmap, beginning implementation of advanced scenarios and increasing data granularity. Through that process, the Companies continue to collaborate with the Joint Utilities in automating processes to improve refresh rates and provide more granular data, which have been a constraint for the Joint Utilities.

Interconnections: The Companies will continue to make progress on Phase 2 automation over the near term as well as Phase 3 automation over the long term. We are currently working to transition over to a web base database and enhancement to the visual aid of the status of a project as it moves through the interconnection process.

The Companies are looking into the future with phase II of the flexible interconnection program. Currently phase II status is that we have submitted a proposal and are waiting for DPS to provide further direction on how to proceed. We are targeting deployment of a total of 7 total flexible schemes by the end of 2028. There is significant work involved in both the policy and technical side. This includes investments in changes to the NYSSIR in contractual obligations and study requirements. There are continuous conversations on flexible interconnections as part of the ITWG and IPWG and will require continued efforts to support stakeholders' needs in 2030 and beyond.

The Companies presented to DPS and Industry on their ongoing initiatives related to flexible interconnection of DERs phase II. The JU will continue with their internal initiatives and share lessons learned with DPS and Industry in 2030 and beyond.

Future implementation efforts support stakeholder needs and state clean energy goals by resulting in increased efficiency in the interconnection application and study processes, which in turn result in increased volumes of DER interconnections. The development of low –cost monitoring and control solutions for DER results in economic benefits to developers. Future implementation of smart inverters functionality is anticipated to provide additional flexibility and higher integration of DERs. NYSEG/RG&E offered a pilot flexible interconnection and is looking into the future with phase II of the program. There is significant work involved in both the policy and technical side. This includes investments in changes to the NYSSIR in contractual obligations and study requirements. There are continuous conversations on flexible interconnections as part of the ITWG and IPWG and will require continued efforts over the next few years.

The JU, along with Industry and DPS Staff, continue to collaborate on activities related to flexible interconnection schemes for DER.

NYSEG/ RG&E and National Grid have presented to DPS and Industry their ongoing initiatives related to flexible interconnection of DER.

Several of the JU members are engaged in pilot projects or are making other foundational investments to establish the building blocks for greater control of DERs, including flexible interconnection. The JU will continue with their internal initiatives and will share lessons learned with DPS and Industry in 2025 and beyond.

These initiatives are anticipated to increase the amount of DER that can be connected to circuits and allow developers to access diverse revenue streams and use cases.

The JU are working with EPRI and stakeholders to implement the adoption of the EPRI CFF for sharing smart inverter settings.

The JU believe that both the utilities and developers will benefit if manufacturers were to adopt the CFF, since this would lead to quicker verification of inverter settings and reduced person-hours per project, which will in turn shorten interconnection timelines.

This has already been observed by a few utilities in NY who have successfully worked with several inverter manufacturers to create inverter grid codes for their respective companies.

Moving forward, the JU will collaborate with Industry to jointly approach inverter manufacturers to implement the CFF functionality.

Following up on these conversations, the JU are intending to implement a requirement for the EPRI CFF implementation by January 1, 2026.

Our plans for the next five years are presented in the Integrated Planning Roadmap (Exhibit 2.2.1-1).

EXHIBIT 2.2.1-1: INTEGRATED PLANNING & INTERCONNECTIONS ROADMAP

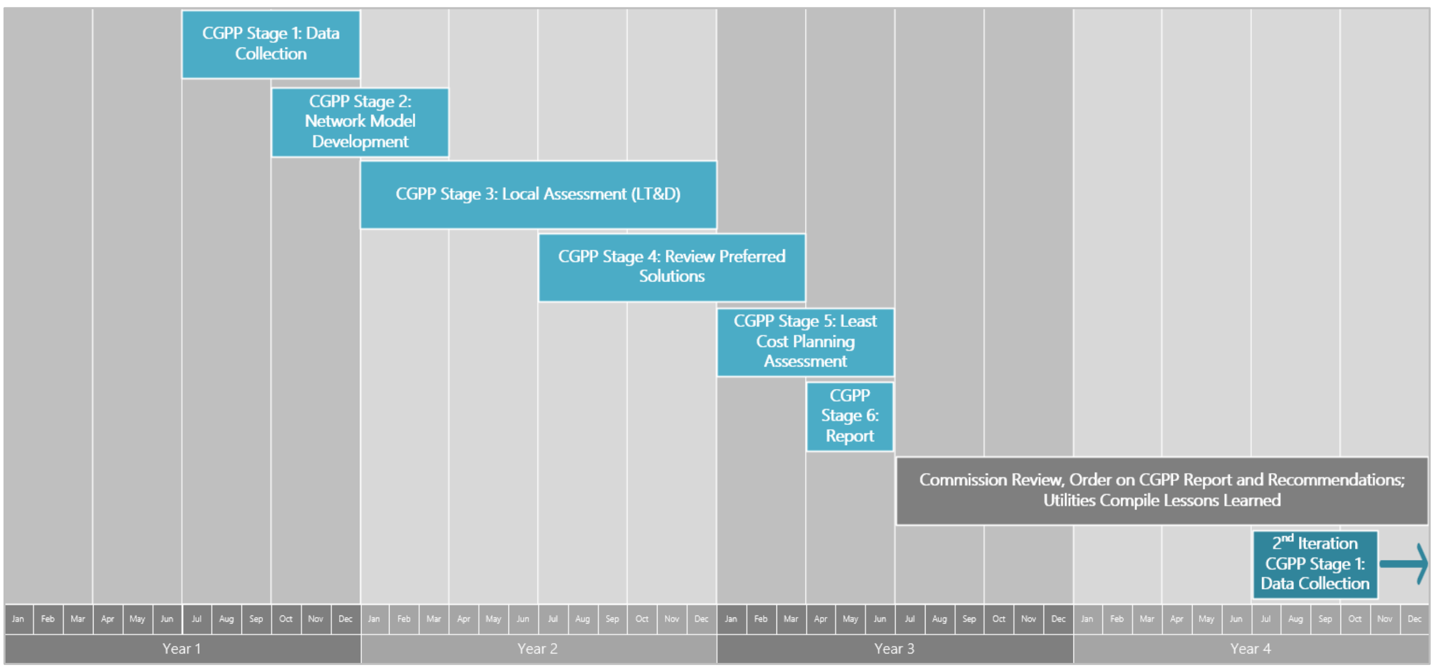
<table>
<tr><th>Capability</th><th>Achievements (2023-2025)</th><th>Short-Term Initiatives (2026-2027)</th><th>Long-Term Initiatives (2028-2030)</th></tr>
<tr><td>Advanced Forecasting</td><td colspan="2">• Short-Term Load Forecasting: Line Sensors Program</td><td>• Long-Term Load Forecasting: SCADA/Automation Program</td></tr>
</table>

Capability	Achievements (2023-2025)	Short-Term Initiatives (2026-2027)	Long-Term Initiatives (2028-2030)
	• SQL Database • Substation EV and HP forecasts • EV/HP impacts at peak • MetrixIDR Pilot	• Customer survey data • Segmentation data from outside vendors • Load research & data analytics resources	• MetrixIDR Companywide implementation
NWAs and Beneficial Locations	• Continue to Implement Measurement and Verification ("M&V") protocols and improved contract administration • Commissioned Stillwater BESS Project • Ferndale Substation (Request for Proposal ("RFP") • Holland Substation RFP • Developed NWA Opportunity Identification and Scoping Process Guide	• Continue to refine M&V and monitoring and control back-end processes • Align projects with CLCPA targets • Incorporate granular AMI and system data into NWA analyses • Use Comprehensive Area Studies to develop more NWA projects for solicitation • Continue to Administer Stillwater contract and leverage lessons learned to inform future NWA projects • Continue to administer Stillwater and monitor its performance • Revisit Java Microgrid and Peak Shaving Project and release RFP if applicable • Execute Ferndale Substation NWA contract and install project • Execute Holland RFP and install project	• Additional NWA deployments • Potential execution of Java microgrid backup supply power and peak shaving project • Leverage lessons learned from NWA projects to continue to refine process' • Take best practices from NWA projects implementation to establish requirements for BESS company-ownership
Hosting Capacity	• PV and ESS Hosting Capacity map updates • Electrification Map Updates:	• Hosting Capacity Data Flows and Automation	• *(Potential)* Hosting Capacity Forecasts (to determine with stakeholder input)

Integrated Implementation Timeline: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2030. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

The exhibit below highlights the Joint Utilities' integrated implementation timeline, illustrating the three-year CGPP cycle, which includes six stages, followed by a Commission review, Order and application of lessons learned to be implemented in the follow-on three-year CGPP iteration.

EXHIBIT 2.1-2: CGPP IMPLEMENTATION TIMELINE



Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

The major risk to realizing planned progress in Integrated Planning is the availability and accuracy of system and customer data to support integrated planning analyses by the Companies. The ability to have accurate load, generation, and distribution infrastructure data to produce accurate and data rich system models for Integrated Planning analysis will become essential as the proliferation of DERs increase. The following initiatives have been identified to mitigate this risk:

- Installing AMI will provide more granular customer usage data, which is crucial for system planning. Accurate customer usage data from AMI is essential for modeling new interconnection loads and DERs during Integrated Planning analysis. Additionally, AMI data is vital for the annual refresh of hosting capacity models.
- Installing line sensors at the head-end of distribution circuits lacking interval data will facilitate future implementation of interconnections, DER, battery storage, and flexible interconnect technology. Enhanced interval data will aid in integrating more battery storage and flexible interconnection technology, optimizing the grid by utilizing this data. Interval data enables time-series analysis, which can be used in DER studies to optimize hosting capacity, allowing for more DER integration compared to using worst-case summer peak values.
- Utilize PI Historian to access and consolidate data from various sources such as AMI, line sensors, SCADA systems, and drag hands. Implementing advanced analytics tools within PI Historian to analyze the collected data. will help in identifying trends, optimizing performance, and making informed decisions when performing DER and Load Interconnects.
- Complete the enhancement of Data Gateway capabilities to transfer SCADA data to CYME by 2027
- Incorporate data into IEDR (see 2.8 Data Sharing) for more details; and

A second and additive source of risk is the timing and success of ongoing efforts vendors to develop methodologies that forecast DERs by location and to reflect probabilistic factors in DERs and load forecasts. Furthermore, while there is a lot of attention being devoted to the methodological challenges, new methodologies cannot be tested using NYSEG and RG&E data until more granular customer and system data is available.

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category's needs will be met over time; Describe and explain the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

Joint Utilities have engaged with stakeholders to provide updates on several initiatives through their newsletters, including advancements in the Grid of the Future work, the new EV program and preparations for the EV Phase-in Rate, IEDR Phase 2, enhancements to the interconnection process, updates to hosting capacity PV and BESS maps, and the implementation of NYISO's DER participation model and the Federal Energy Regulatory Commission ("FERC") Order 2222. Additionally, bi-annual webinars are hosted to engage stakeholders on DSP services, Stakeholders can also access the JU DER Granular Dispatch Data Whitepaper, which outlines day-ahead information sharing requirements for the NYISO DER participation model.

DER developers are a key constituency for the Integrated Planning function. Our engagement in developing PV and BESS hosting capacity maps for stakeholders is representative of continuing engagement efforts. The Companies engage with DER developers during the design process, solicit feedback shortly after a new methodology is applied (and results shared through web portals), and then implement improvements based on the feedback. Individual feedback is provided on a regulator basis when developer submits a request for a new DER specifically when the company has done an impact study.

Some improvements are easy to make and are prioritized; others require more substantive implementation efforts and will occur in steps.

Stakeholders also provided valuable input on the areas where they want to see the most improvement in future versions of hosting capacity. After actively engaging with stakeholders on enhancements that will provide them with the greatest value in the next iteration, the Joint Utilities consult to agree on the next areas of focus in developing Stage 4.0. The Joint Utilities also routinely issue a newsletter, which provides updates on hosting capacity maps and other topics. The Joint Utilities host webinars multiple times a year and provide a mailbox for which stakeholders can contact the Joint Utilities.

Additional Detail

The utility's electric system plan must position the utility to timely integrate an increasing number and variety of DERs while maintaining or improving safety, reliability, quality, and affordability of service. Utility planning analyses based on known information and advanced forecasts will have to evaluate an increasingly complex and dynamic system environment where the combined behaviors and mutual effects of loads and supply resources can vary significantly.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to the utility resources and capabilities which support integrated electric system planning:

NYSEG and RG&E are building an Integrated Planning function that will accommodate large numbers of DERs and NWAs, to be considered along with more traditional utility investments when planning the grid. We are focused in the near term on continuing to build foundational data and methodological capabilities and associated processes that support the range of specific Integrated Planning functions (*e.g.*, advanced forecasting, hosting capacity, and procurement of NWAs).

1. *The means and methods used for integrated system planning.*

As noted above, we are also developing six functions within Integrated Planning. Please see Current Progress and Future Implementation above for more details.

2. *How the utility's means and methods enable probabilistic planning which effectively anticipates the inter-related effects of distributed generation, energy storage, electric vehicles, beneficial electrification, and energy efficiency.*

NYSEG and RG&E will work with industry vendors and the Joint Utilities to develop probabilistic forecasting methodologies that address the primary sources of uncertainty. We anticipate our planning studies will incorporate forecasts of all DERs, and that power flow models will incorporate the location and other attributes of DERs. This approach will capture the interrelated effects of various DERs.

These DER forecast inputs depend on the behavior of third parties and customers in response to technical, economic, and other factors. While predictive behavioral models will certainly improve as historical data is available for estimation purposes, there will always be some uncertainty around assumptions used to produce forecasts as well as typical statistical variances. Scenario analyses can help determine how the uncertainty attributable to DER forecasts impacts planning results.

While there is a lot of industry attention being devoted to developing probabilistic forecasting methodologies, the methodologies cannot be tested until more granular data is available.

3. *How the utility ensures that the information needed for integrated system planning is timely acquired and properly evaluated.*

Accurate data representation of the network, including circuits, devices, connected DERs, and meters, is critical for Integrated Planning. Granular data on network flows, power injections, and loads inform Advanced Forecasting analyses and enable Power Flow Model analyses, including traditional infrastructure solutions as well as NWAs. This data also supports Hosting Capacity analyses. To ensure data quality and timeliness, the GMEP project includes developing a data governance process to improve the quality of information used by Integrated Planning for power flow analysis. These processes involve field audits to validate Geographic Information System ("GIS") accuracy and compliance checks to maintain data integrity and accuracy. Additionally, they focus on proper equipment identification used in models for DER, interconnections, and generating available hosting capacity models.

4. *The types of sensitivity analyses performed and how those analyses are applied as part of the integrated planning process.*

Sensitivity analyses typically estimate the impact on an outcome (or dependent variable) based on a change in an important assumption (or independent variable). They are most valuable when making decisions based on a forecast that may change significantly if one or more drivers are beyond the control of the utility and potentially subject to wide variation. NYSEG and RG&E anticipate that a number of assumptions will impact the DERs and load forecasts, including:

- The number, type, operating capabilities, and location of various types of DERs, particularly where such forecasts depend on customer decisions in response to emerging technologies and/or offerings by third party DER providers.
- Weather conditions.
- Economic development activities and general economic conditions; and
- Environmental policy and market assumptions.

Each of these factors is a candidate for sensitivity analyses. The applicability of sensitivity analyses will depend on the type of analysis being performed and the purpose of the analysis.

Planning decisions will consider base case as well as sensitivity analyses, with an explanation as to how various analyses contributed to the final decision. However, our first priority is to address the availability and quality of data that are inputs into planning analyses and developing our forecasting methodologies.

5. *How the utility would timely adjust its integrated system plan if future trends differ significantly with predictions, both in the short-term and in the long-term beyond the DSIP timeline.*

Annual capital plans will be based on current integrated system plans. Our Integrated Planning function will prepare work products (*e.g.*, hosting capacity forecasts, solutions to distribution system needs included as inputs to the NWA Suitability Criteria, etc.) throughout the year, and produce results that are reflected in our annual five-year capital plan. These work products will reflect the best available data, adjusting long-term forecast assumptions as trends emerge. It is conceivable that particular project or NWA procurement decisions could be accelerated, delayed, or reprioritized within a planning year in response to extraordinary developments (*e.g.*, the planned shutdown or expansion of a large load). We also anticipate that the development of the EV charging station market and the potential for building electrification will require adjustments to our system plans.

6. *The factors unrelated to DERs – such as aging infrastructure, electric vehicles, and beneficial electrification – which significantly affect the utility's integrated plan and describe how the utility's planning process addresses each of those factors.*

There is a direct relationship between "asset management" capital projects that reflect the need to address aging infrastructure and Integrated Planning. For example, a planned replacement of a 4kV distribution line can be upgraded to a 12kV line to increase hosting capacity if doing so will attract DERs that are beneficial to the grid and accommodate future customers' needs, such as EV adoption or new or expanded facilities. NYSEG and RG&E have criteria that are used to make asset management decisions to explicitly consider opportunities to optimize the network by making incremental and economical enhancements to projects that benefit the grid and our customers.

There is a diverse collection of beneficial electrification opportunities that have the potential to reduce customer costs, improve the environment, improve productivity, contribute to economic development and improve workforce safety. These include residential and commercial heat pumps, electrification of forklifts and other industrial or warehouse equipment, commercial food service equipment, industrial processes, and heat recovery chillers in commercial and industrial facilities, and the electrification of transportation and increased reliance on EVs. The Integrated Planning function will need to monitor these trends, including supporting government policy or Commission actions, and reflect them in load forecasts. Additionally, upgrade considerations must factor in DER procurement in order to realize the full benefit of distribution investment deferral value of the NWA, as detailed in the NWA Suitability Criteria.

7. *How the means and methods for integrated electric system planning evaluate the effects of potential energy efficiency measures.*

NYSEG and RG&E consider energy efficiency as the first option to help curb customer demand. Energy efficiency programs provide incentives to install measures or participate in active and passive demand response programs. These programs and measures help reduce electric consumption during peak hours. Targeted Energy Efficiency and Demand Response programs have been successful in providing long-term savings by deferring capital investments.

It is important to identify and exhaust all energy efficiency opportunities before identifying a NWA solution for the targeted area. Sometimes, an NWA solution can complement an energy efficiency program by increasing the incentives provided through the typical program. NYSEG and RG&E estimate the location and amounts of anticipated energy and peak load reductions to identify areas where an NWA solution would be appropriate. Developing and targeting energy efficiency options to areas of the system expected to need investments to meet capacity needs will result in the greatest cost savings, an outcome expected to be seen in project-specific benefit-cost analysis (BCA).

The sustained impact of past energy efficiency programs is reflected in the load forecasts, a practice that NYSEG, RG&E, and other utilities have applied for years. However, it is anticipated that the ability to reflect locational energy efficiency in databases and forecasts will improve with AMI and other foundational investments in place. Additionally, applying new data analytics to customer usage data from AMI and other data from internal databases and public demographic information will allow for targeted communications to customers, offering insights regarding energy efficiency opportunities and actions they should consider.

8. *How the utility will inform the development of its integrated planning through best practices and lessons learned from other jurisdictions.*

NYSEG and RG&E expect to continue to collaborate with the Joint Utilities to share best practices and lessons learned from within and beyond New York. The Companies have utility affiliates the United States, Europe and South America that will also share best practices and lessons learned. Our subject matter experts in our Global Practice Groups attend conferences and read the industry press to keep abreast of developments within their respective areas of responsibility.

As noted above, the Joint Utilities have collaborated with stakeholders on several Integrated Planning issues through Load and DER Forecasting and Hosting Capacity engagement groups. Many of our stakeholders bring experiences from other jurisdictions to these discussions. We expect this sharing of intelligence to continue as we work with stakeholders to address DER forecasting and hosting capacity forecasting issues.

2.2 Advanced Forecasting

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2023 DSIP Update filing.

Advanced forecasting refers to the capability to produce load and DER forecasts by location and day/hour of the year. Advanced forecasting supports integrated system planning and grid operations while enabling DER developers to make informed investment decisions. Granular forecasts provide system planners with long-term projections of load and DERs by location and time, reflecting electrification trends and state policy goals. These forecasts must be sufficiently granular with respect to location (e.g., by feeder) and hour of the year to support the integration and optimization of connected DERs. Additionally, they aid in evaluating utility programs and tariffs designed to incentivize efficient investment and electricity usage decisions.

Each type of DER presents distinct forecasting challenges. A meaningful increase in electric load due to EVs and other electrification initiatives will substantially impact load and hourly consumption profiles. This must be reflected in the Advanced Load Forecasting methodology to support integrated planning. While the industry now has EV load shapes available, and the Companies have access to EV data from the New York DMV (NY DMV), the capability to confirm or test these readily available load shapes against actual metered usage is currently limited. This limitation is due to AMI meters not being fully integrated or deployed. As AMI rollout continues at NYSEG and RG&E, the ability to validate hourly forecasts is expected to be realized by 2026.

Studies on medium and heavy-duty EVs highlight unique challenges and opportunities tied to electrification in these sectors. These vehicles, including trucks and buses, disproportionately contribute to greenhouse gas emissions and require tailored infrastructure investments, such as high-capacity charging stations. Electrification of school buses is also advancing, supported by initiatives like the EPA's Clean School Bus Program, which provides funding to replace diesel buses with electric models. These efforts reduce emissions, improve air quality, and offer long-term cost savings for school districts.

Traditional forecasting for electric load was developed using "top-down" econometric models that allocate regional forecasts to specific utility divisions. Advanced forecasting, however, uses a "bottom-up" approach. This method forecasts electric load for each individual circuit and substation based on the characteristics of the customers located on each circuit and substation

The "bottom-up" approach integrates a range of data sources to enhance forecasting accuracy. These include:

- **Individual customer billing data** facilitated through AMI deployment (though full data access is pending system integration).
- **SCADA and sensor data** to provide real-time insights into circuit and substation performance.
- **EV and HP adoption data** by substation and circuit, offering localized insights into electrification trends.
- **Load research, customer segmentation information, survey data, and appliance saturation rates**, enabling a detailed understanding of customer behaviors and equipment adoption.
- A **pilot program** is set to launch in 2025 to test leveraging AMI and SCADA models for energy storage coordination (ESC).
- Consideration of **seasonal variations**, including distinct winter and summer load patterns, to account for differing consumption profiles throughout the year.

As DERs, energy storage, EV and heat pump penetration increase, circuit load shapes are expected to change significantly. Understanding annual, daily, and even hourly load shapes will be critical when designing the network, moving beyond a narrow focus on peak periods.

Current Progress: Describe the current implementation as of June 30, 2025; describe how the current implementation supports stakeholders' current and future needs.

As previously stated, Avangrid's Data Science team has successfully developed an SQL database specifically designed to support granular load forecasting efforts. This database includes monthly billing data for every customer, EV registration data, EV charging infrastructure data, and heat pump customer data, all mapped to individual distribution feeders to enhance forecast precision. This comprehensive database will play a critical role in informing future bottom-up forecasting models. In addition to these efforts, the team is actively collaborating with vendors to acquire additional customer segmentation and load research data that could further refine and improve bottom-up forecasting models. The team is engaged with internal customer service and digital experience team to leverage their interactions with customers to get more customer segmentation and appliance type. A dedicated Load Research and Data Analytics team has also been established to further understand and help predict customer usage and electrification trends. These combined efforts will yield a more comprehensive understanding of consumer behavior and will better inform bottom-up forecasting models.

The Companies are leveraging multiple data sources to build a robust load research database, including surveys, DMV records, heat pump rebate information, and vendor-provided data such as appliance insights from Experian. These initiatives aim to capture detailed heating and cooling appliance inventories by customer, enabling the creation of more accurate feeder-level load forecasts that reflect localized adoption trends and appliance saturation rates.

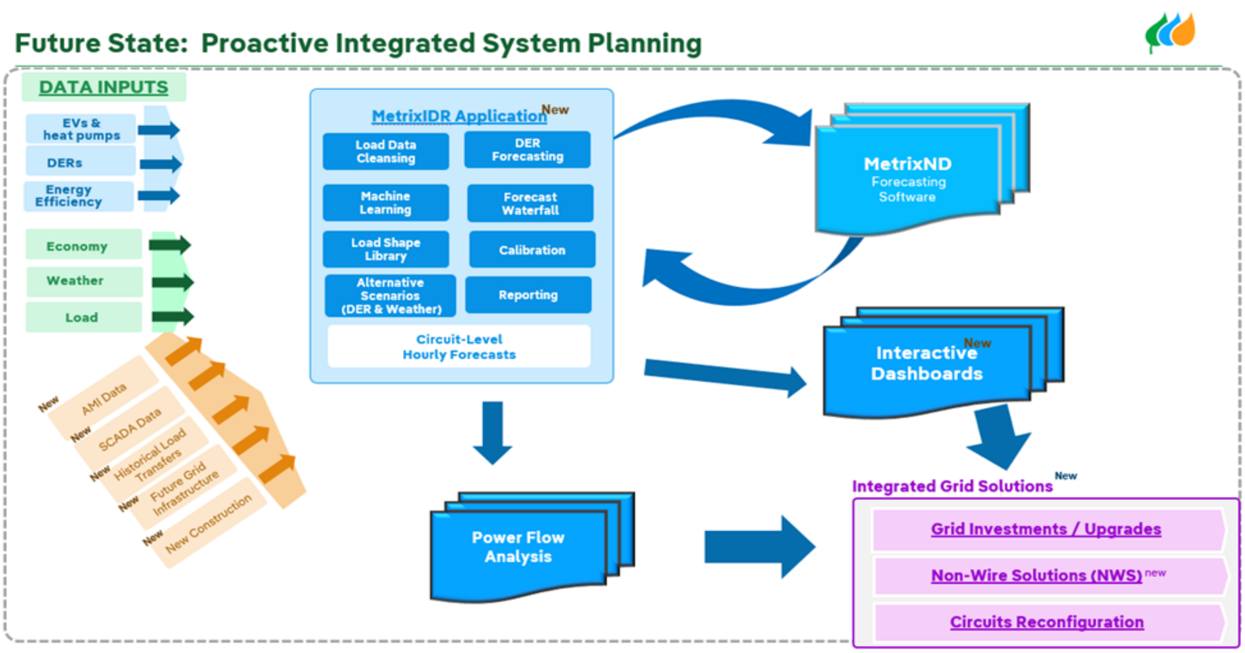
As the AMI project progresses, the Companies are working diligently to access and utilize AMI data, with some progress already made into leveraging AMI and SCADA/sensor data stored in the Companies' data lake. These efforts are laying the groundwork for a granular load forecasting pilot project, funded under 22-E-0317, et al., which is expected to begin in July of this year. This integration of AMI and SCADA data is expected to provide valuable insights into system operations and enhance forecasting granularity and accuracy. In parallel, preparations are underway to launch the advanced load forecasting pilot project that will test advanced software capable of integrating AMI, SCADA, and DER/EV/HP data to generate long-term, time-series (8,760-hour) forecasts at the distribution feeder level. This software, proposed as part of the Companies' next planned rate filing, aims to address gaps in SCADA data by leveraging AMI data, and vice versa, thereby enhancing bottom-up forecasts. Designed for seamless compatibility, the software will integrate easily with existing forecasting tools and other databases used by the forecasting team, providing a solid foundation for more accurate, localized forecasts and improved capacity planning. Additionally, the impact of EVs and HPs on peak load by distribution substation has been assessed using Bass-Diffusion modeling for adoption curves and the NREL Pro-Lite tool for estimating peak demand. Registration data for EVs was gathered from the NY DMV. While information for HPs has been more challenging to obtain, the Companies have had some success with identifying HP conversions through NYSERDA rebates. This approach has provided greater visibility into areas with high adoption rates and enhanced system insight into future needs.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2030, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2030 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation; Described where and how plans for topic-related work and investments affect the CGPP; Describe where and how *investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.*

As previously stated, once the previously mentioned advanced load forecasting pilot is completed and working successfully, the Companies will look to implement the pilot application (Metrix IDR) on a companywide level. The Companies have researched solutions that leverage AMI, DER, SCADA, electrification adoption, and customer segmentation data to inform and create distribution substation/circuit-level time-series forecasting. The Advanced Load Forecasting effort is designed to improve the granularity of load forecasting, including EV, HP, and DER adoption in terms of time, location, and impact on the distribution system. The project would allow for the development of models that assess adoption and load impact from EVs, electric heat pumps, and other related market trends. Additionally, impacts of different variables like rate design, managed charging programs, and other factors that might alter load shapes can also be simulated. Using an Advanced Load Forecasting tool, distribution system planners can address both short-term circuit trends and long-term grid expansion needs while remaining consistent with the overall corporate load forecasts for energy and peak demand. This tool will enable planners to analyze specific future scenarios/simulations such as high/low solar penetration, electric vehicle, and heat pump adoption. This will better inform the Companies' capacity and proactive planning efforts as well as address the forecasting priorities outlined in New York's DSIP efforts under the REV proceeding.

As the Companies currently utilize ITRON's MetrixND forecasting software for both their sales and peak load forecasting processes, it was reasonable to research advanced analytical applications that would work synergistically with MetrixND. ITRON provides a granular forecasting application, called MetrixIDR, that pairs with the MetrixND software but also ingests AMI and SCADA data, and a host of other data streams, to produce long-term time series forecasts at the distribution feeder level. Additionally, the MetrixIDR software allows for multiple simulation scenarios to be run for each circuit, such as various levels of DER or EV or HP adoption and produce reports on each with its interactive dashboards. With the MetrixIDR software application, the Companies would be able to produce long-term hourly load forecasts on every distribution circuit that could then be aggregated up to a corporate level hourly load forecast. This approach would allow for more robust time series (i.e., hourly) analysis to better inform system planning efforts, more optimally align possible Non-Wires Solutions (NWS), and significantly improve visibility of the grid. Additionally, this proposed Advanced Load Forecasting approach would allow the Companies to comply with several of the DSIP priorities. Exhibit 2.2-1 below displays the proposed Advanced Load Forecasting solution employing ITRON's MetrixIDR forecasting application.

EXHIBIT 2.2-1: FUTURE STATE



To progress from the current pilot implementation to a system-wide rollout, significant work and investment are required. This includes the addition of labor capital, specifically hiring a data scientist and additional load research support. Establishing a dedicated department will be crucial, as it will actively engage in refreshing data and interacting with billing and distribution planning. To achieve this the Companies have proposed in its upcoming rate case initiatives to improve granular load forecasting capabilities to better meet the needs of capacity and proactive T&D planning for building and transportation electrification as well as for distributed energy resources ("DER"). Additionally, electrification adoption trends and State policy goals imply more circuits and substations will transition to winter peaking. Understanding these impacts and forecasting for both winter and summer hourly loads and peaks at the circuit level is quickly becoming a planning requirement across the Companies' service territories. The Companies propose initiatives to improve granular load forecasting capabilities, including studies to collect customer segment and market data, inform EV and heat pump adoption rates, and identify load shapes. The Companies will also implement advanced load forecasting software that will integrate AMI data, Supervisory Control and Dad Acquisition ("SCADA") data, customer information, and forecast models to provide hourly circuit level forecasts. The Companies propose incremental FTEs to improve granular load forecasting capabilities to better meet the needs of capacity and proactive planning, while also improving the forecasting process in response to recommendations in the Companies' management and operations audit. Furthermore, the success of this transition is contingent upon the receipt of funding requested in the Companies' rate cases, which will provide the necessary financial resources to support these enhancements and ensure a smooth and effective implementation.

The exhibit below shows our advanced forecasting roadmap.

EXHIBIT 2.2-2: ADVANCED LOAD FORECASTING ROADMAP

<table>
<tr><th>Capability</th><th>Achievements
(2023-2025)</th><th>Short-Term Initiatives
(2026-2027)</th><th>Long-Term Initiatives
(2028-2030)</th></tr>
<tr><td rowspan="2">Load and DER Forecasting</td><td colspan="2">• Short-Term Load Forecasting: Line Sensors Program</td><td>• Long-Term Load Forecasting: SCADA/Automation Program</td></tr>
<tr><td>• SQL Database
• Substation EV and HP forecasts
• EV/HP impacts at peak
• MetrixIDR Pilot</td><td>• Customer survey data
• Segmentation data from outside vendors
• Load research & data analytics resources</td><td>• MetrixIDR Companywide implementation</td></tr>
<tr><td>Probabilistic Forecasting</td><td></td><td colspan="2">(Potential) Develop Probabilistic Forecasting</td></tr>
</table>

<u>Integrated Implementation Timeline</u>: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2030. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

To create an integrated implementation timeline for the five-year period ending in 2030, it is essential to outline key milestones and dependencies for all topic-related work and investments. Initially, the SQL database must be populated with AMI and SCADA data before the pilot deployment. This foundational step ensures that the necessary data infrastructure is in place to support the pilot. The success of the company-wide implementation is contingent upon the pilot's success, highlighting the importance of thorough testing and validation during the pilot phase. Additionally, securing funding is crucial, as it will provide the financial resources needed to support these efforts and ensure a smooth transition from pilot to full-scale implementation. Obtaining approved funding through the recently filed NYSEG and RG&E rate cases will play a pivotal role in enabling these investments and facilitating the overall timeline.

2023-2025:

Developed SQL database dedicated to compiling all data required to inform Advanced Load Forecasting, to include:

AMI and Billing data for each customer by circuit
SCADA data
EV registration data mapped to circuit
HP conversions data mapped to circuit
DERs mapped to circuit
Customer segmentation / load research / survey data
Energy Efficiency data by customer/circuit

As noted in previous DSIP filings, access to quality data is foundational for any successful planning initiative. With the roll out of AMI and SCADA across the NYSEG and RG&E service territories, access to quality data and gaining visibility to actual granular loads is opening the doorway to more advanced load forecasting. The company has leveraged internal data scientists to develop a dedicated SQL database to manage all data required to inform Advanced Load Forecasting.

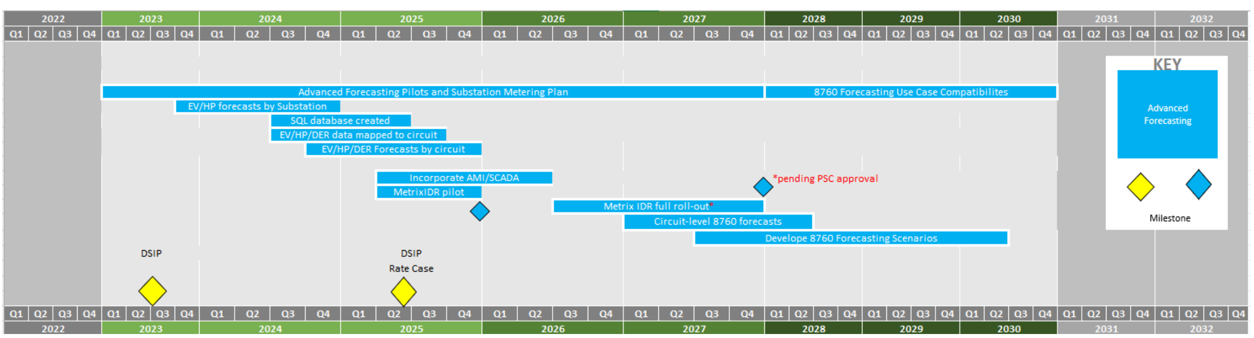
With the data foundation nearing completion, NYSEG plans to run a pilot starting in July of this year of ITRON's MetrixIDR Advanced Load Forecasting application over four distribution substations / 14 circuits and roughly 13,000 customers. The MetrixIDR software will pull AMI and SCADA data, MetrixND forecast models and several other data streams to generate long-term hourly load forecast simulations on each distribution circuit in the pilot scope. Additionally, the MetrixIDR platform will allow for running multiple EV/HP adoption scenarios. The MetrixIDR pilot is expected to be completed by early 2026. With insight gained from the pilot, the Advanced Load Forecasting group will engage with Distribution Planning to review the forecast results of the pilot and seek feedback to better support integrated system planning efforts. Once a refinement of the MetrixIDR forecasting pilot results is completed and optimized for distribution planning efforts, the Companies would look to implement the Advanced Load Forecasting process across the full NYSEG and RG&E service areas.

2026-2027:

In the Companies next planned rate filing, NYSEG and RG&E have requested funding and resources to support this system-wide roll out of MetrixIDR advanced load forecasting application. With rate case resolution expected around Q2-2026, the Companies would plan for full NYSEG and RG&E system-wide implementation of MetrixIDR system to begin in Q3-2026 through Q2-2027, pending PSC approval of funding. This timeline, if followed, would allow the Companies to provide dynamic, circuit-level hourly load forecasts as part of the 2027 DSIP filing.

The Integrated Forecasting implementation timeline is displayed in Exhibit 2.2-3 below:

EXHIBIT 2.2-3: ADVANCED LOAD FORECASTING TIMELINE



<u>Risks and Mitigation</u>: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E have identified two risks that relate to performance of the Advanced Forecasting function, and have taken measures to mitigate both risks, as shown in Exhibit 2.2-4.

EXHIBIT 2.2-4: ADVANCED FORECASTING RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Data:** DSO performance will depend on the quality data that is relied upon by the DSO to perform Advanced Forecasting	• NYSEG and RG&E have proposed to implement AMI to collect actual granular usage data throughout its service territory to develop more accurate load shapes. Timely implementation of AMI would contribute to mitigation. • Build redundancy into AMI telecommunications infrastructure. • Grid Automation will enable SCADA to have greater visibility into power flows and performance along the network, which will improve advanced forecasting. • NYSEG and RG&E are designing the GMEP Phase 1 to incorporate governance and data processes and flows. • Completing the integrated distributed system model, which tracks the location and operating attributes of all DERs.
2. **Forecast Methodology:** Forecasting using AMI/SCADA data and DERs is a relatively new application and will require advanced modeling applications, segmented customer data and third-party decisions.	• Collaborating with other New York utilities and monitoring advances in DER forecasting in other jurisdictions • Running MetrixIDR application pilot leveraging AMI/SCADA/DER/EV/HP and other customer segmentation data to generate 8,760 granular forecasts

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category's needs will be met over time; Describe and explain the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems..

The Companies participate in the Joint Utilities' Integrated Planning Working Group and Advanced Forecasting Subgroup to enhance forecasting processes and improve planning strategies. Discussions restarted in early 2023, focusing on advanced load and DER forecasting improvements.

The Companies and the rest of the Joint Utilities, have engaged with stakeholders to provide updates on several initiatives through their newsletters, including advancements in the Grid of the Future work, the new EV program and preparations for the EV Phase-in Rate, IEDR Phase 2, enhancements to the interconnection process, updates to hosting capacity PV and BESS maps, and the implementation of NYISO's DER participation model and FERC Order 2222. Additionally, bi-annual webinars are hosted to engage stakeholders on DSP services, Stakeholders can also access the JU DER Granular Dispatch Data Whitepaper, which outlines day-ahead information sharing requirements for the NYISO DER participation model.

DER developers are a key constituency for the Integrated Planning function. Our efforts in developing PV and BESS hosting capacity maps for stakeholders are representative of continuing engagement efforts. The Companies, along with the rest of Joint Utilities, engage with DER developers during the design process, solicit feedback shortly after a new methodology is applied (and results shared through web portals), and then implement improvements based on the feedback. Individual feedback is provided on a regulator basis when developer submits a request for a new DER specifically when the company has done an impact study.

Some improvements are easy to make and are prioritized; others require more substantive implementation efforts and will occur in steps.

Stakeholders also provided valuable input on the areas where they want to see the most improvement in future versions of hosting capacity and load forecasting. After actively engaging with stakeholders on enhancements that will provide them with the greatest value in the next iteration, the Joint Utilities consulted to agree on the next areas of focus in developing Stage 4.0. The Joint Utilities also routinely issue a newsletter, which provides updates on hosting capacity maps and other topics. The Joint Utilities host webinars multiple times a year and provide a mailbox for which stakeholders can contact the Joint Utilities.

Additional Detail

Utility planners and operators, DER developers and operators, and other stakeholders all require load and supply forecasts which are timely, accurate, and detailed enough to support both short-term and long-term planning. Such forecasts are an important factor in predicting the hosting capacity available at existing and potential DER locations and *are necessary for efficient development and use of grid resources. As the variety of methods for using DERs to address electric system needs expands, utilities must perform advanced forecasting analyses which integrate an increasing number and variety of DERs into their load and supply forecasts.*

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to the utility resources and capabilities which enable advanced electric system forecasting and provide the most current forecast results:

1) *Identify where and how DER developers and other stakeholders can readily access, navigate, view, sort, filter, and download up-to-date load and supply forecasts.*

   We currently perform an update of the granular Load/DER forecasts once every two years to satisfy the DSIP filing requirements. We do not currently have a stakeholder interface to share forecasts, however, if a stakeholder requests a forecast for a particular substation, we provide it. We also have not had discussions with stakeholders on how ofter these forecasts should be updated, as no DER developer has requested this over the past several years. At the present time any stakeholder can request forecasts by substation by reaching out to the Companies' Regulatory Administration team.

   Once the advanced load forecasting process is up and running the Companies envision embedding and linking the long-term circuit-level 8760 forecasts to the existing hosting capacity maps for a full one-stop experience for external DER developers and operators.

2) *Identify and characterize each load and supply forecasting requirement identified from stakeholder inputs.*

   The Joint Utilities have solicited and received stakeholder feedback on several forecasting topics, including the role of 8760 forecasts, incorporation of external inputs to utility forecasts, such as public policy and developer forecasts, and the future evolution of forecasting to incorporate more probabilistic methods and scenario analyses. Based on these discussions, we believe that delivering 8760 load and supply forecasts by distribution substation and by circuit in the future, with further disaggregation by type of DER to the extent possible will meet DER developer needs. Ongoing discussions by the Joint Utilities' Integrated Planning are addressing stakeholder needs and requirements.

3) *Describe in detail the existing and/or planned forecasts produced for third-party use and explain how those forecasts fulfill each identified stakeholder requirement for load and supply forecasts.*

   We are currently providing granular load forecasts, net of the contribution of DERs. The existing methodology is an input to system planning analyses, interconnection studies, hosting capacity estimates, and the information provided to NWA bidders. Our next steps are to improve the input data by leveraging AMI and SCADA information as it becomes available throughout our service areas, improve the DER Interconnections database, build out customer segmentation and load research database, develop the integrated distributed system model, and develop valid forecasts by type of DERs and beneficial electrification with spatial and temporal granularity. The Line Sensors Program and AMI rollouts, will provide the Companies with more accurate load shapes, as discussed above. We expect to make significant progress in all areas and gain significant insights from the pilot project running ITRON's MetrixIDR software. This will mark a significant step in towards a robust advanced load forecasting application that will allow the Companies to develope circuit-level 8760 forecasts based on actual AMI and SCADA usage data.

Ongoing discussions by the Joint Utilities' Integrated Planning will continue to address stakeholder needs and requirements.

4) *Describe the spatial and temporal granularity of the system-level and local-level load and supply forecasts produced.*

The ultimate goal is to develop distribution circuit-level hourly (8,760) forecasts including the ability to distinguish hourly load impacts of DER installations, EV adoption and HP conversions. Additionally, the ability to simulate multiple adoption scenarios will allow for granular sensitivity analysis based on actual data. The MetrixIDR application meets this requirement with feeder-level 8,760 forecasting and scenarios analysis.

5) *Describe the forecasts provided separately for key areas including but not limited to photovoltaics, energy storage, electric vehicles, and energy efficiency.*

The Companies have historically relied on top-down forecasts for DER. These system-wide forecasts were apportioned to circuits based on existing substation data and could be used for disaggregating. A corporate-level forecast was produced for each DER and then disaggregated among the distribution substations to meet the DSIP filing requirements.

In 2024, the Companies began development of a "bottoms up" approach to forecasting by distribution substation. Organic growth [i.e. peak growth expected to occur outside of the electrification of transportation (EV) and buildings (heat pumps)] is estimated for each substation. The Companies developed granular Bass Diffusion models to produce distribution substation-level forecasts of both EV adoption and Heat Pump conversions and estimated the impact of each on both summer and winter substation peaks. The combination of organic growth and forecasting incremental electrification are applied to each substations weather-adjusted actual peak to generate a substation-level MW peak forecast. Aggregated representative load shapes based on the customer mix served by each substation are then applied to estimate long-term hourly load forecasts. Load shapes currently used are deemed load shapes by customer class, the same load shapes utilized in monthly settlements process, however, the Companies are moving towards utilizing actual AMI-derived load shapes in the futre. This current process can be characterized as a pseudo ”bottoms up” forecasting approach as certain top-down forecasting assumptions are still relied upon. This pseudo “bottoms up” approach represents a step towards more granular load forecasting. A full bottoms-up advanced load forecasting effort will require additional tools and resources and the Companies are looking forward to continuing along this journey towards a complete advanced load forecasting process.

6) *Describe the advanced forecasting capabilities which are/will be implemented to enable effective probabilistic planning methods.*

The approach to developing advanced forecasting capabilities is described in the Future Implementation and Planning section as well as in Section 7 below.

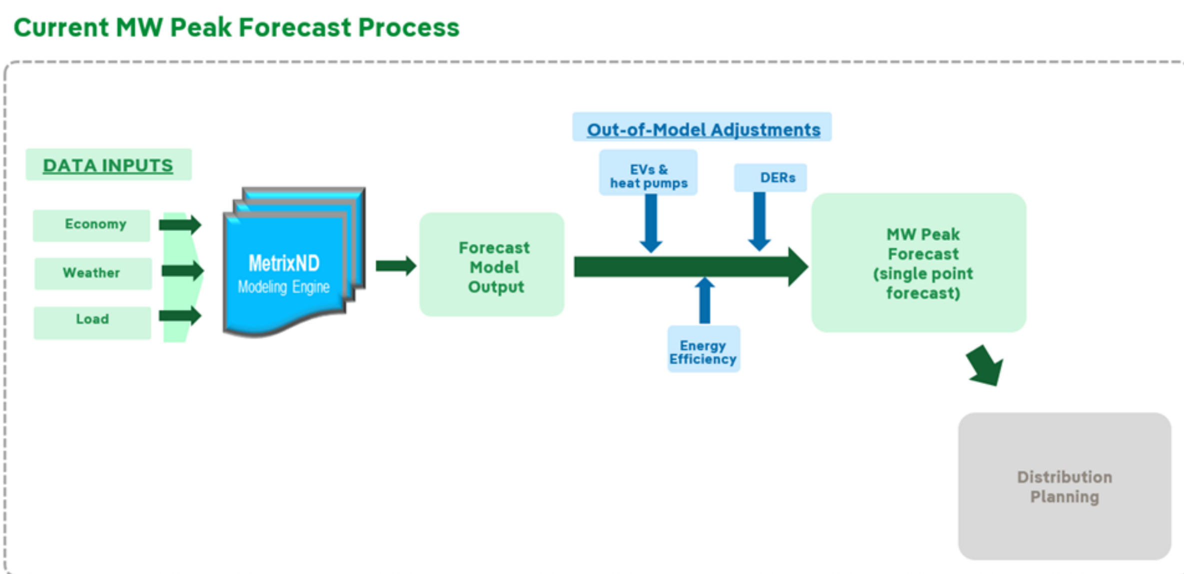
7) *Describe how the utility’s existing/planned advanced forecasting capabilities anticipate the inter-related effects of distributed generation, energy storage, electric vehicles, beneficial electrification, and energy efficiency. In particular, describe how electric vehicle, energy efficiency, and building electrification forecasts are reflected in utility forecasts.*

The Companies are focused in the near term on continuing to build foundational processes that will support large numbers and different types of DERs. We are beginning to incorporate energy efficiency, energy storage, and electric vehicles into all of our Integrated Planning processes, and building a data foundation that will track the type, location and other attributes of DERs. Integrated Planning’s primary analytical engine is the Power Flow Model, a tool that relies on an up-to-date mathematical representation of the physical and electrical attributes of distribution infrastructure that comprise the network, system flow data from our SCADA system and AMI, a forecast of loads by circuit, and the location and operational attributes of connected and forecasted DERs.

EXISTING:

The current electric peak forecasting process is designed to produce both summer and winter static point forecasts of system peaks which limits the information available for system planning purposes. As shown in Exhibit 2.2-5 below, a set of underlying exogenous variables representing weather conditions, the economy and seasonality are used to estimate an econometric model used to predict summer and winter system peaks. Historically, the Companies would prepare a corporate-level MW peak forecast. Incremental adjustments to the forecast were made to account for EV adoption, HP conversions and Energy Efficiency impacts. This corporate-level growth rate was then applied across all distribution substations to grow that last available actual MW peak to generate substation-level MW peak forecasts. These forecasts were winter and summer MW peak point forecasts as actual interval data was not available. To comply with DSIP filing requirements, the Companies' utilized the deemed load shapes by customer class to simulate hourly (8760) forecasts. The deemed load shapes were representative load shapes for a northeast utility and are utilized in the company supply settlement process. The lack of available actual SCADA or AMI data prevented assessment of the accuracy of this approach.

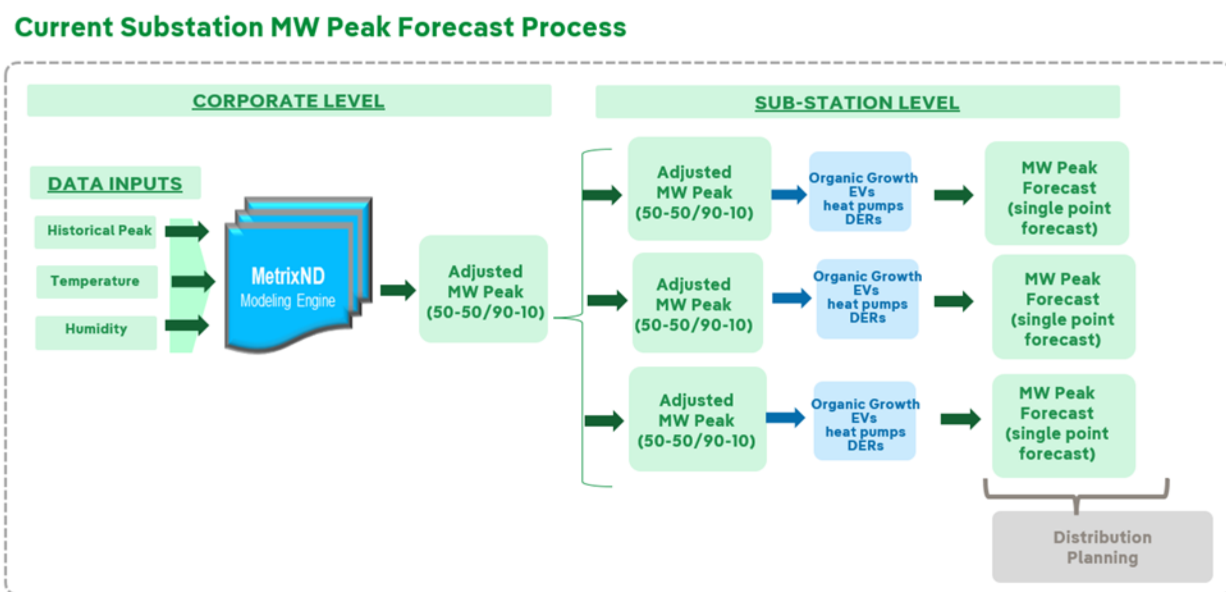
EXHIBIT 2.2-5 CURRENT MW PEAK FORECAST PROCESS



In 2024, the Companies obtained both EV and HP data at the most granular level available and begin to develop distribution substation-level forecasts of EV and HP adoption via Bass Diffusion models of technology adoption. EV and HP impacts on both winter and summer peak were estimated using publicly available load shapes. Additionally, localized organic growth factors were estimated for each substation, based on the customer mix served by each sub and their assumed rates of growth. These peak point forecasts are then disaggregated across the Companies' distribution substations via an algorithm that incorporates bottom-up assumptions for organic growth, EV adoption and heat pump conversions. The local organic growth coupled with EV and HP adoption forecasts generated summer and winter substation MW peak forecasts. This approach, albeit still a MW peak point forecast, allowed for the diversity of geospatial electrification trends as well as localized growth. This approach is demonstrated in Exhibit 2.2-6 below

To comply with DSIP filing requirements, the Companies continue to utilize deemed load shapes by customer class to simulate hourly (8760) forecasts. The deemed load shapes are representative load shapes for a northeast utility and are utilized in the company supply settlement process. The lack of available actual SCADA or AMI data prevented assessment of the accuracy of this approach.

EXHIBIT 2.2-6: CURRENT SUBSTATION MW PEAK FORECAST PROCESS



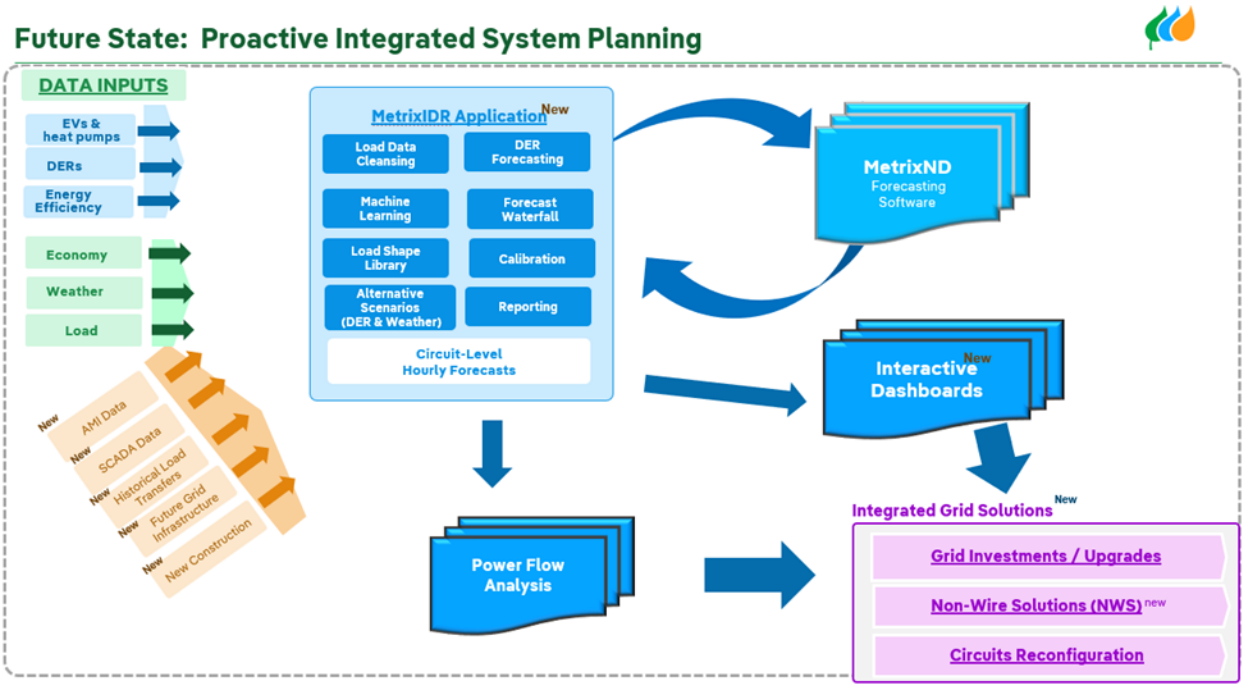
PLANNED:

Consistent with the priorities outlined the DSIP, NYSEG and RG&E have researched solutions that leverage AMI, DER, SCADA, electrification adoption, and customer segmentation data to inform and create distribution substation/circuit-level time-series forecasting. The Advanced Load Forecasting effort is designed to improve the granularity of load forecasting, including EV, HP, and DER adoption in terms of time, location and impact on the distribution system. The project would allow for the development of models that assess adoption and load impact from EVs, electric heat pumps, and other related market trends. Additionally, impacts of different variables like rate design, managed charging programs, and other factors that might alter load shapes can also be simulated. Using an Advanced Load Forecasting tool, distribution system planners can address both short-term circuit trends and long–term grid expansion needs while remaining consistent with the overall corporate load forecasts for energy and peak demand. This tool will enable planners to analyze specific future scenarios/simulations such as high/low solar penetration, electric vehicle, and heat pump adoption. This will better inform the Companies' capacity and proactive planning efforts as well as address the forecasting priorities outlined in New York's DSIP.

Historically, this static system peak forecasting approach provided system planners with the forecasts sufficient to prioritize infrastructure investments. With the technological advancements of AMI, SCADA and big data analytics, as well as PSC priorities for Integrated System Planning, new tools are required to leverage the available granular detail and inform a dynamic advanced load forecasting process at the distribution circuit level.

As NYSEG and RG&E currently utilize ITRON's MetrixND forecasting software for both its sales and peak forecasting processes, it made sense to research advanced analytical applications that would work synergistically with MetrixND. ITRON provides a granular forecasting application, called MetrixIDR, that pairs with the MetrixND software but also ingests AMI and SCADA data, and a host of other data streams, to produce long-term time series forecasts at the distribution feeder level. Additionally, the MetrixIDR software allows for multiple simulation scenarios to be run each circuit, such as various levels of DER or EV or HP adoption, and produce reports on each with its interactive dashboards. With the MetrixIDR software application, the Companies would be able to produce long-term hourly load forecasts on every distribution circuit that could then be aggregated up to a corporate level hourly load forecast. This approach would allow for more robust time series (i.e. hourly) analysis to better inform system planning efforts, more optimally align possible NWAs and significantly improve visibility of the grid. Additionally, this proposed Advanced Load Forecasting approach would allow NYSEG and RG&E to comply with several of the NY PSC DSIP and Proactive Planning priorities. Exhibit 2.2-7 below displays the proposed Advanced Load Forecasting solution employing ITRON's MetrixIDR forecasting application.

EXHIBIT 2.2-7: FUTURE STATE



8) *Describe in detail the forecasts produced for utility use and explain how those forecasts fulfill the evolving utility requirements for load and supply forecasts.*

Please see previous response to Part Section 7 above

9) *Describe the utility's specific objectives, means, and methods for acquiring and managing the data needed for its advanced forecasting methodologies.*

"Acquiring and Managing the data" is a foundational requirement that is being addressed with the "integrated distribution system model" initiative, described in (2.1 Integrated Planning). The Companies will be able to leverage AMI and system data to test integrated distribution planning and load forecasting models to more accurately forecast DER integration and system impacts as more and more AMI and and Distribution Automation grid devices are installed. We will also continue to leverage data we have and use in our existing load forecasting methodology. Towards this end a unified forecasting SQL database was developed in 2024 with the goal of being the central repository for granular-level AMI, SCADA, DER, Electrification, EV and Customer Segmentation data. This foundation forecasting database allows for the testing and implementation of advanced load forecasting tools, initially the ITRON MetrixIDR pilot application previously described. Longer term, the Companies have requested a dedicated full time data science resource as well as load research resources to manage, update and refine the centralized forecasting database and data needs in their recently filed rate cases.

10) Describe the means and methods used to produce substation-level load and supply forecasts.

See Current Progress and Future Implementation sections above for our near-term Line Sensors Program and longer-term SCADA/Automation Program, which will support granular forecasts.

11) Describe the levels of accuracy achieved in the substation-level forecasts produced to date for load and supply.

We define "accuracy" as the expected variance around a particular forecast. The accuracy of our existing forecasts decreases as they become more granular. Thus, our NYSEG and RG&E service area load forecasts are the most accurate, with diminished accuracy as we produce forecasts with greater spatial definition (*i.e.,* by substation and then by circuit). The forecasts become less accurate as we add time granularity because we are currently relying on generic load curves. The DER supply forecast is the least accurate aspect of our forecast as we need to gain more experience, gain insights into customer behavior, and develop new methodologies to develop these forecasts.

The accuracy of the existing substation-level forecasting approach is difficult to measure and will continue to be so until such time as actual substation-level SCADA data is available. The majority of substation peaks have been recorded with very rudimentary devices, such as drag-hands, that reveal neither the date nor time of the peaks. This lack of detail precludes any validation of the actual peak or analysis of the load shape, including weather analysis, of the peak and day of the peak. The Companies are in the process of full scale roll out of SCADA and line sensor systems across all substations. The forecasts will improve as we collect AMI and more detailed SCADA data, and improve our DER/Electrification database. Because forecasting is dependent on the quality of data in the models, we are looking to incorporate additional sources of data into our forecast models such as system monitoring information, meteorological data, and customer segmentation and demographic data. Additionally, the availability of actual hourly load data (AMI and SCADA) will enable a true validation of the accuracy of the substation-level forecasts.

12) Describe the substation-level load forecasts provided to support analyses by DER *developers and operators and explain why the forecasts are sufficient for supporting those analyses.*

The previously described evolution of the Companies load forecasting process, with the planned roadmap to an advanced 8760 circuit-level load forecasting methodology, will provide the visibility at the most granular level. By leveraging actual AMI/SCADA data, the real-time hourly load forecasts will provide the robustness required by DER developers and operators for their analyses.

Once the advanced load forecasting process is up and running the Companies envision embedding and linking the long-term circuit-level 8760 forecasts to the existing hosting capacity maps for a full one-stop experience for external DER developers and operators.

13) Provide sensitivity analyses which explain how the accuracy of substation-level forecasts is affected by distributed generation, energy storage, electric vehicles, beneficial electrification, and energy efficiency measures.

At the present time, the Companies do not have the capability (i.e. data or tools) to perform sensitivy analysis of substation-level forecasts. See Current Progress and Future Implementation sections above for our near-term Line Sensors Program and longer-term SCADA/Automation Program, which will support granular forecasts and provide sensitivity analysis capabilities. With deployment of AMI meters/ SCADA and acquisition of tools required to leverage AMI and SCADA data as decribed in the Advanced Load Forecasting development plans the company expects to be able to perform sensitivity analysis and analyze the accuracy of substation-level forecasts. Specifically forecast accuracy of distributed generation, energy storage, electric vehicles, beneficial electrificaton and energy efficiency measures and the impacts on substation-level hourly loads.

14) Identify and characterize the tools and methods the utility is using/will use to acquire and apply useful forecast input data from DER developers and other third parties.

Please see previous response to Part Section 7 above.

15) Describe how the utility will inform its forecasting processes through best practices and lessons learned from other jurisdictions.

We will continue to participate in the Joint Utilities' working groups. Additional coordination with the other Joint Utilities will be required to align forecasting methodologies. The Companies, and the rest of the Joint Utilities are working on gathering information from other jurisdictions on forecasting efforts to inform our own forecasting development. NYSEG and RG&E actively participate in several industry forecasting groups, such as ITRON's Energy Forecasting Group, Electric Utility Forecaster's Forum ("EUFF"), EEI Load Forecasting group, ISO-NE Load Forecasting Committee ("LFC") and Distributed Generation Forecast Working Group ("DGFWG") and NYISO Load Forecast Task Force ("LFTF"). The forecasting staff regularly attend training opportunities on current utility forecasting issues offered by leading utility industry groups like NREL, EEI, EPRI, EUCI, ITRON and others. NYSEG and RG&E will continue to work with counterparts at other AVANGRID operating companies to capture lessons learned and share best practices regarding smart grid technologies, including advanced load forecasting and integrated grid planning initiatives.

16) Describe new methodologies to improve overall accuracy of forecasts for demand and energy reductions that derive from EE programs and increased penetration of DERs. In particular, discuss how the increased potential for inaccurate load and energy forecasts associated with out-of-model EE and DER adjustments will be minimized or eliminated.

The move away from non-strategic EE programs and focusing on strategic and more measured EE programs, such as the Clean Heat Program, as described in the 2.7 Energy Efficiency Integration and Innovation, will allow for more accurate quantification of results. Improvements to measuring results from EE impacts will reduce the uncertainty surrounding EE impacts and lead to more accurate load and energy forecasts.

We currently forecast energy efficiency attributable to our own programs, although we do not disaggregate these forecasts by location or time period. Having access to complete granular data will improve forecast accuracy and allow for analysis of DERs and EE impacts on hourly loads. Improvements in load and DER monitoring will provide better insights into energy efficiency program efficacy, which will in turn improve forecasting, providing a feedback loop going forward as new information on programs is incorporated.

17) Describe where CGPP forecast information can be found.

On December 27, 2022, the New York Utilities filed a "Coordinated Grid Planning Process Proposal," in Case 20-E-0197, Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act. The proposal includes the Energy Policy Planning Advisory Council ("EPPAC"), who will represent stakeholder interests across New York state. The EPPAC will provide input and feedback on assumptions and the technical approach used in the CGPP analysis. The proposal includes the EPPAC, among other items, will provide input into the "scenarios" which will include assumptions related to load forecasts and shapes.

2.3 Grid Operations

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2023 DSIP Update filing.

Grid Operations is the DSO function that manages, maintains, and operates the electric power system to deliver system stability, power quality, and reliability. The Companies are incorporating the ability to integrate large numbers of DERs into all Grid Operations functions. Our objective is to improve the reliability and quality of service to our customers and DER developers. Grid Operations activities over the next several years is focused on implementing grid automation and management to improve reliability and grid visibility, as well as coordinating with NYISO on DER aggregation.

Grid operations focuses on developing grid operations capabilities to manage, maintain, and operate the electric power system to deliver system stability, power quality, and reliability, as well as NYISO coordination on DER aggregation. Our main objective is to improve the reliability and quality of service to our customers and developers. We are developing the ability to integrate large numbers of DERs into grid operations.

Over the long term (beyond 2030), this initiative facilitates visibility and control of all new DERs connected to the distribution grid, regardless of size, for protection and optimization to increase system efficiency, reliability, and safety. This will require that grid operators and the DSO be aware of all DERs in the system, their grid connection, potential grid contributions, control capabilities (e.g. direct control or through third-party providers, telecommunication protocols, etc.), and market program incentives or constraints that may impact the ability to control the resources.

Grid operations will rely on:

1. An up-to-date detailed inventory of all DERs and an accurate connectivity model of the distribution system including all distribution equipment and their characteristics. Currently the ECC receives quarterly updates on our DER contact list along with circuit description and kW ratings.
2. Near real-time data regarding customer usage and power flows throughout the distribution grid. Progress in our AMI deployment has improved customer outage response and customer usage.

3. Load and generation forecasting technology to enable grid operators to plan for future grid needs on multiple time scales (hour ahead, day ahead, week ahead, etc.)

4. Systems and technology that respond automatically to mitigate potential issues and support grid operators in resolving operational issues. We continue insulation of loop auto, sectionalizing schemes and field reclosers to improve our outage response technology.

The exhibit below highlights the Companies' grid operations capabilities developed through this initiative, including:

1. Control Center Systems and Grid Optimization

Control Systems are software and supporting hardware that process data and information to provide situational awareness, evaluate control options, and regulate the operation of grid devices. Our ECC will continue to be responsible for grid operations under constantly changing network conditions, utilizing grid-side, supply-side, and demand-side resources. The Companies are developing a platform technology that will consolidate both the Energy Management System ("EMS") and ADMS into a single hardware and software platform that manages centralizes grid control for the transmission area as well as centralized management for the devices in the distribution area. The ADMS consolidates distribution SCADA, outage management, and advanced distribution applications onto a "single pane of glass" for distribution operators and engineers.

The ADMS will be the core system for monitoring, control, and management of the distribution network to achieve reliability, efficiency, and cost-effective integration of DERs. We envision the ADMS will provide decision support to assist operators in the ECCs and help them coordinate the safe and efficient work of field operating personnel. The ADMS will also manage operation of switching equipment through Fault Location, Isolation and Service Restoration ("FLISR") and, over the long term, voltage control equipment through Volt-Var Optimization ("VVO") on the distribution network. Over time, the ADMS will leverage an expanding network of grid devices and advanced software applications to support feeder optimization. In the future, ADMS will interact with other systems to enable ANM, which, among other capabilities, will enable higher total hosting capacity and more efficient integration of DERs on the distribution system.

Some of these systems depending on the vendor selected may include mobility, crew management, AMI, State Estimators, Power Flow, and DERMS. In the Transmission side, EMS will include applications such as Transmission Network

Applications ("TNA"). Crew management and mobility has improved since our deployment of field force in early 2025. As of the time of writing, the requirements for the implementation of the ADMS have not yet been established, and a vendor has not been selected. Therefore, additional details cannot be provided at this stage. Once the full requirements are defined and a vendor is chosen to execute the ADMS at Avangrid, further details will be available.

2. Grid Automation

Grid automation devices measure, monitor, and adjust electric power parameters on the distribution system. These devices can be found on poles, pads, and in substations. They may also be installed at a customer's premise, or as part of a DER installation or EV charging station. Examples include sensors, smart meters, relays, switches, reclosers, capacitors and voltage regulators. Grid automation devices, supported by an electronic communications infrastructure to deliver data between grid devices and central control systems, will improve the quality of service to customers, grid reliability and resiliency, and grid efficiency. The Companies are focused on grid automation at two levels:

<u>SCADA/Automation Program</u>: The goal of this program is to install a remote terminal unit ("RTU") in all substations that do not currently have an RTU, and to integrate all the bays into the SCADA system of those stations where there is an RTU already in service. This program covers the replacement of electromechanical relays with digital relays to digitize the bays. The addition of SCADA in the substations in conjunction with the installation of digital relays will allow for improved visibility and remote control, proper system protection coordination, and outage assessment, which in turn will result in quicker response and improved reliability metrics. Remote control capabilities will contribute to an increase in the safety of workers operating the switchgear, preventing them from performing manual commands.

<u>Line Automation</u>: Line automation refers to the automation of grid devices throughout the grid (between the substations and grid edge). These technologies provide operators with visibility, decision support, and the ability to make physical adjustments to distribution system infrastructure from their desks in the ECC. Automation of reclosers and switches makes it possible to isolate power outages so fewer customers are impacted. Applying electronic controls to capacitor banks and voltage regulators supports coordinated voltage and reactive power control that can improve distribution voltage profiles to decrease energy losses, improve power quality, and accommodate more variable DERs.

3. DER Management

Coordination and control of DERs ensure network reliability and facilitates full participation of owners, operators, and aggregators. A DERMS will provide situational awareness and coordination capabilities for DERs. The DERMS will enable the DSO to forecast, coordinate, and optimize DER operations. The DERMS can be broken down into two main sub-systems, a Centralized DERMS closely linked to the Companies' ADMS that identifies and solves grid needs and an Aggregator DERMS which communicates to third-party DERs over a variety of pathways to achieve the desired response. The Aggregator DERMS will interface with DERs both at the site-level via local utility owned DER Gateways and at the aggregation level, in concert, the Centralized DERMS and the Aggregator DERMS will allow the Companies to manage a wide variety of DER, including solar, battery energy storage, EV charging, smart thermostats, smart hot water heaters, and building energy management systems. The Companies have utilized basic DERMS functionality to monitor and control larger DERs (larger than 500 kW) as part of their Flexible Interconnection Capacity Solution ("FICS") REV Demo. This demonstration accommodates additional DER capacity that would normally pay for expensive system upgrades by enabling the DSO to control DER output to avoid thermal and voltage violations on the distribution system. This capability benefits DER developers and customers by reducing the cost of upgrades associated with interconnections. The Companies filed an Intermediate Summary Report in July 2024 sharing the results and lessons learned from the FICS REV Demo up to that point. Some of the lessons learned shared in the FICS Intermediate Summary Report included:

Deploying more advanced DER Monitor and Control (M&C) technologies such as the ANM system utilized in the Demo requires changes to both utility and DER developer control architectures.

Limited interoperability between DER control systems and utility control systems

In some locations, Flexible Interconnection effectively increases hosting capacity and makes it possible to interconnect more DER capacity on distribution feeders.

The Companies are proposing to leverage these lessons learned in a revised FICS REV Demonstration Project Implementation Plan which incorporates integrating additional DER technologies through a flexible capacity auction and to integrate flexible EV charging. The lessons learned from the original FICS REV Demo and the revised implementation plan are expected to inform the expansion of future DERMS capabilities.

4. NYISO Coordination

We are also coordinating our operations with the NYISO to ensure the reliability of our own distribution and lower-voltage transmission systems and the New York high-voltage transmission grid, while providing access of distribution-connected DERs to NYISO markets. Since the 2020 DSIP, FERC issued Order No. 2222 in an effort to remove barriers preventing DERs from competing in capacity, energy, and ancillary services markets facilitated by the NYISO. FERC issued its Order 2222 on September 17, 2020. FERC Order No. 2222 allows for the aggregation and participation of DERs in regional wholesale electricity markets, paving the way for a more competitive, greener electricity industry. This historic order necessitates innovative preparation as utilities, regional grid operators and other actors collaborate to plan complex system changes. The Joint Utilities are excited to face this challenge and have already addressed many topics, including operational coordination, registration and enrollment, telemetry implementation, and metering and settlement. NYISO received conditional approval of its FERC Order 2222 compliance filing on June 16, 2022, for filing tariff revisions filed on July 19, 2021. The proposed tariff revisions were intended to resolve any gaps between the FERC's September 2020 Order and the NYISO's existing DER participation model, accepted by the Commission in January 2020. Key tariff updates included provisions related to the: (i) interconnection of DERs for the exclusive purpose of participating in an aggregation; (ii) prevention of double counting of services provided by a DER; and (iii) coordination among the NYISO, Aggregators, and Distribution Utilities. FERC issued an Order on June 17, 2022, accepting the NYISO's compliance filing, and directing the NYISO to make over thirty additional tariff modifications to achieve compliance with Order No. 2222. NYISO then extended its DER market design timeline from fourth quarter 2022 to second quarter 2023. In December 2022, FERC approved the NYISO's request of up to three more years to implement tariff revisions to allow DERs in aggregations to provide ancillary services. The NYISO is targeting 2026 for implementation. NYISO identified areas in its previously accepted tariff where revisions were necessary to clarify previously accepted concepts and align the tariff with NYISO's software implementation. On February 15, 2023, NYISO submitted a Federal Power Act ("FPA") Section 205 filing, which focused on DER minimum capabilities, to FERC containing these revisions to become effective simultaneously with the scheduled deployment of DERs in 2023. Since that time, NYISO has worked toward the deployment of the DER market design in tandem with its FERC Order 2222 compliance initiative. The NYISO has stated it expects DER aggregator registration to begin in the second quarter of 2023 but that aggregators are not expected to transact in the NYISO markets until approximately August 2023, or when their compliance filing requesting activation of their market design was approved by FERC. FERC approved NYISO's DER interim market design on April 15, 2024, the order leaves in place NYISO's 10 kW minimum capacity, but requires NYISO to report in two years on experiences with the minimum capability. This report to include views on the feasibility to allow for smaller than 10 kW DER to participate in the future, determining the number of smaller DER in NY and the potential contributions of resources, and an update on stakeholder engagement related to smaller resources being able to participate. The NYISO is targeting the launch of its fully compliant FERC Order 2222 market no later than December 31, 2026.

Current Progress: Describe the current implementation as of June 30, 2025; describe how the current implementation supports stakeholders' current and future needs. There is currently a project underway to assure that NYSEG and RG&E are prepared for FERC Order 2222. A project team is in place and a new process model has been established to support aggregation enrollments. A communication link to being setup to provide the necessary telemetry, and a support model is being determined.

Our grid operations efforts are underway, as detailed below:

Control Center Systems and Grid Optimization: The ADMS pilot project successfully tested concepts in the Energy Smart Community ("ESC") and has current functionality to perform Automated Grid Recovery/Restoration ("AGR") (also referred to as FLISR) in a few network substations including: Langner Road and Silver Creek in the Lancaster Division as well as Tom Miller Road in the Plattsburgh Division. Since then, the Companies have begun reviewing the systemwide deployment, after which, the Companies will integrate advanced applications (e.g., AGR and VVO). The full ADMS capabilities and advanced applications will not be available through the entire service territory until all substations are fully digitized and the GMEP survey is complete. The ADMS deployment is dependent upon parallel projects in line and substation automation, AMI deployment, and the GMEP to realize the full benefits of ADMS. The Outage Management System ('OMS") has been upgraded and tested to support AMI deployment and ETR response.

Energy Control Center Systems

NYSEG and RG&E currently engaged in the "NEW YORK HARDWARE and SOFTWARE REFRESH PROJECT. Planned for go-live in 2025, the objective of this project is to upgrade the hardware and software platforms to support upgraded versions of the system operating system and database management system that support the Siemens Spectrum Power v4.75 System. While core functionality of the Spectrum System will not change there are additional tools and functionality incorporated into the Refresh of the system. Items such as, "Dual Representation" will fill gaps identified over time from system operations. The newer hardware combined with updated operating and database systems are expected to provide more robust system performance and maintenance coverage supporting the application platform. The additional tools and functionality to be implemented will provide increased control and operation over the grid. The project will also incorporate the latest version of OMS R16 currently implemented in the production environment.

Grid Automation: This initiative refers to the automation of grid devices, which allows grid operators to control devices and maintain visibility in real time. Grid automation refers to substation automation (automating grid devices within substations) and line automation (automating devices throughout the electric grid).

> SCADA/Automation Program: The primary objective of this program is to enhance the operational efficiency and reliability of our substations by installing RTUs in all substations that currently lack them. For substations already equipped with RTUs, the program aims to integrate all the bays into our master SCADA system. This integration will ensure seamless communication and control across the network, facilitating better management and monitoring of the substations. By having a unified SCADA system, we can streamline operations and improve the overall performance of our power distribution network. To date, we have installed a significant number of RTUs and automatic devices with SCADA control.
>
> In addition to the installation of RTUs, the program includes the replacement of outdated electromechanical relays with modern digital relays. This upgrade is crucial for the digitalization of the bays, enabling more precise and reliable system protection. Digital relays offer advanced features such as self-diagnostics, event recording, and remote configuration, which are not available in electromechanical relays. By transitioning to digital relays, we can significantly enhance the protection and control capabilities of our substations, ensuring they are equipped to handle modern power distribution demands.

The integration of SCADA with digital relays will provide improved visibility and remote control of the substations. This enhanced visibility allows for real-time monitoring and quick identification of issues, leading to faster response times and better outage management. Proper system protection coordination and outage assessment will result in improved Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Frequency Index (SAIFI) performance over the long term. These improvements are essential for maintaining a reliable power supply and minimizing the impact of outages on customers, thereby enhancing customer satisfaction and trust in our services.

Furthermore, providing remote control capabilities will greatly enhance the safety of our workers. By allowing operators to control the switchgear remotely, we can reduce the need for manual intervention, which can be hazardous. This not only increases the safety of our personnel but also ensures more efficient and accurate operation of the substations. Remote control capabilities also mean that our response teams can address issues more swiftly and effectively, reducing downtime and improving the overall reliability of the power supply.

The program also emphasizes the importance of proper system protection coordination and outage assessment. By integrating SCADA with digital relays, we can achieve better coordination and quicker identification of faults, leading to faster restoration times. This will result in improved CAIDI and SAIFI performance, which are critical metrics for evaluating the reliability of our power distribution network. Enhanced performance in these areas will contribute to a more stable and dependable power supply for our customers.

Line Automation: In the long term, these substation and line automation devices will be remote capable, connected with the ADMS through a telecommunications network to provide centralized coordination to monitor and control grid devices to ensure grid reliability. This automation will result in reduced customer outage minutes, fewer field crew truck rolls, and increased system efficiency. In addition, the Companies continue testing both centralized and decentralized AGR schemes.

DER Management:

The Companies current DER Management solutions cover both Large DERs (>500 kW) and Small-to-Medium DERs (<500 kW). The solutions also cover both Distributed Generation as well as load-based DERs. For all large DG sites over 500 kW, the Companies require a utility-owned Point of Common Coupling (“PCC”) recloser be installed as part of the upgrades required to interconnect the site. This PCC recloser provides both real-time monitoring (in the form of three-phase performance measurements) and real-time control (in the form of remote disconnection) of these large DG sites. As a part of FICS REV

Demonstration Project, the Companies have deployed a DER Gateway which provides enhanced DER Management capabilities to 4 large DG sites in their service territories. The DER Gateway solution, paired with the centralized DER Management system also deployed on the FICS project, allows the Companies to automatically curtail the output of the DG sites based on grid measurements from the Companies' EMS system, which allows the Company to interconnect DG on distribution substations and feeders that would normally require expensive grid upgrades to accommodate additional DG penetration. The approach reduces interconnection costs for large DG sites and ultimately for New York customers. Starting on January 1, 2023, the Companies began to require all new DG applications to comply with UL 1741 Supplement B (UL 1741 SB) which includes advanced grid interactive functionality including Voltage-Reactive Power curves and Momentary Cessation. These advanced functions and the associated Company specified settings require DERs adapt their output to the conditions on the local grid to improve power quality and increase the amount of DER that interconnect certain parts of the utility grid.

Launched on July 17, 2023, the Companies' Residential Managed Charging Program is engineered to optimize home EV charging, thereby enhancing grid stability, and facilitating the transition to sustainable energy resources. By incentivizing EV owners to charge during off-peak hours, the program mitigates grid stress.

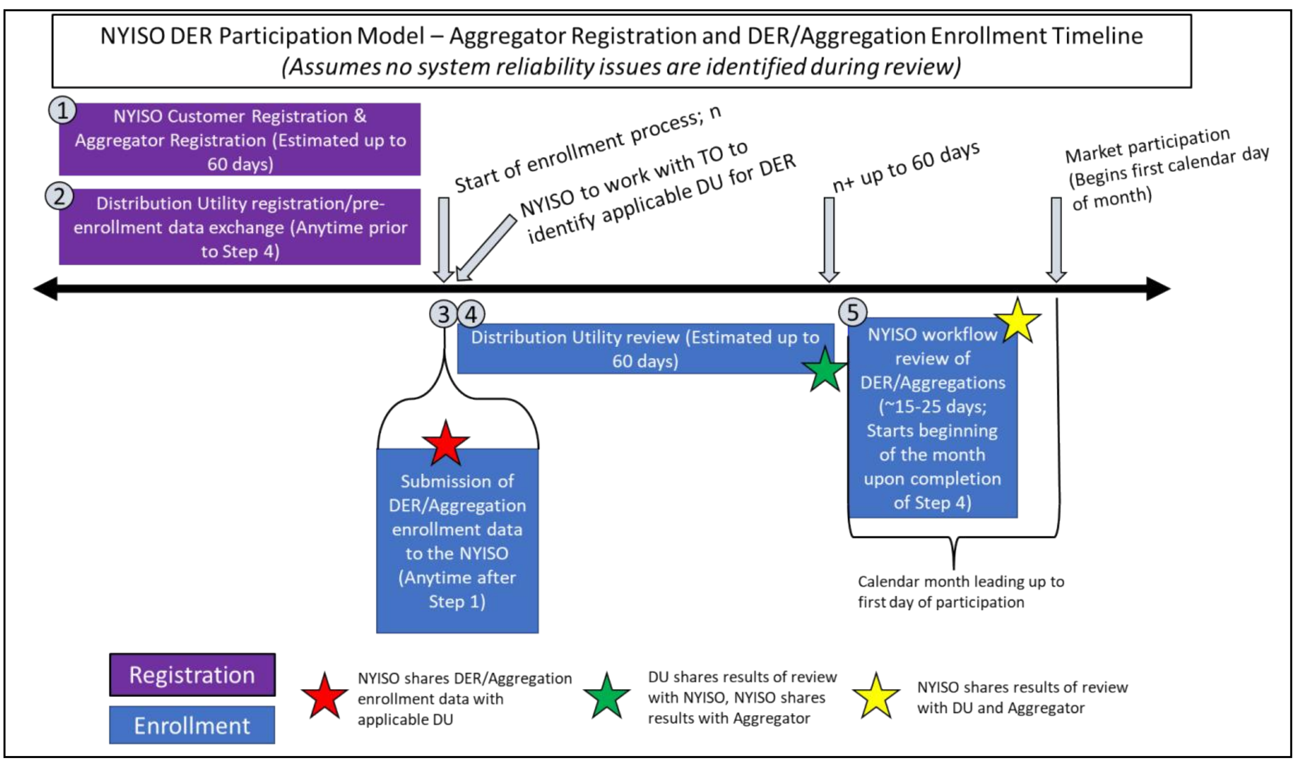
The program comprises two tiers of participation, each designed to accommodate different levels of consumer engagement and technological capabilities. In the passive tier, participants independently monitor their charging schedules. They are required to shift a specified percentage of their charging load to off-peak periods, effectively flattening demand curves and alleviating peak load pressures on the grid. Participants in this tier receive ongoing financial incentives based on their compliance with predetermined load-shifting targets set by the Companies.

In contrast, the active tier facilitates a more integrated approach where participants provide their desired charging completion times. The Companies employ advanced load management algorithms to dynamically manage the charging process through a third-party platform, optimizing load distribution across the grid. This tier allows for adjustments based on grid conditions and renewable energy availability, promoting enhanced grid resilience. Participants in the active tier earn ongoing incentives contingent upon their adherence to the Company-managed charging schedule, which includes restrictions against manual overrides that could disrupt the optimized charging strategy and reduce the benefit to the grid.

Overall, the Residential Managed Charging Program yields significant benefits for the Companies by reducing peak load, improving grid reliability, and enhancing demand response capabilities. EV owners are incentivized through reduced charging costs and financial rewards, fostering greater engagement in sustainable energy practices. Furthermore, the program aligns with regulatory goals aimed at reducing greenhouse gas emissions and provides critical data insights to inform future energy policy development.

NYISO Coordination: The Companies continue to work with the Joint Utilities and NYISO to coordinate on DER procedures to maintain the reliability of utility distribution systems and New York's high-voltage transmission grid, as well as aggregate energy storage systems. As the presence of DERs on the grid grows, aggregators, NYISO, and grid operators will require synchronized resource data and multiple real-time communication flows to ensure a reliable and secure grid. As part of the Joint Utilities, the Companies have made progress on coordination with NYISO. The Joint Utilities also partnered with the NYISO to develop an integrated DER integration workflow and information set, covering resource registration and enrollment, operational coordination, and metering and settlement. This includes the 2020 tariff, as well as FERC Order 2222 changes. On April 14,2024, FERC approved NYISO's DER market design which leaves in place a 10 kW minimum capability but requires NYISO to report in 2 years on experiences with the minimum capability. FERC Order 2222 fully compliant rules to be in place no later than December 31, 2026. There is a FERC Order 2222 project in place that is actively working with aggregators to establish a communication link and begin enrollments in 2025. The FERC Order 2222 project will remain active through full compliancy at the end of 2026. The current NYISO DER participation model (*i.e.*, DER integration workflow) is shown below.

EXHIBIT 2.3-1: NYISO DER PARTICIPATION MODEL



The Joint Utilities also analyzed and identified tariff changes necessary to enable the NYISO's FERC Orders 2222 and 841[18] compliance market. The Joint Utilities filed a request with the Public Service Commission in September of 2022 requesting approval for these tariff changes. In substance, the changes are meant to preclude dual market participants from receiving duplicative compensation in both wholesale and retail markets concurrently. The Joint Utilities also defined the day-ahead information sharing requirements for by DERs participating in the NYISO wholesale market either individually or through an aggregator with the utility required to ensure safe and reliable operation of the system. The group also identified and communicated short-term metering and billing limitations to the NYISO and has a pending launch of information portals on the utility websites for DER Aggregators.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2030, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2030 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation; Described where and how plans for topic-related work and investments affect the CGPP; Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

Through 2030, the Companies will be focused on deploying the platform technologies that will enable the core capabilities required for Grid Operations: monitor and control of the grid and coordinating with NYISO. Longer term, the Companies are developing plans to fully integrate DERs into the operation of the grid. The timing of many actions will depend on the availability and testing of new technologies as well as the timing and approval of full funding needed for major investments. Lessons learned from prior efforts and innovation projects will be reflected in project plans as they occur.

Control Center Systems and Grid Optimization: The ADMS deployment is expected to be completed in 2033-2034, though some aspects to the ADMS are available currently. The Companies will then integrate advanced applications (e.g., AGR), integrate ADMS with the OMS, automation devices, and the GMEP. The ADMS deployment is dependent upon parallel projects in line and substation automation, AMI deployment, and the GMEP to realize the full benefits of ADMS. The Companies are also upgrading the OMS, expected to

[18] FERC Order 841, issued February 15, 2018, directs regional grid operators to remove barriers to entry for energy storage resources in wholesale power markets. The Order is available here: https://www.ferc.gov/media/order-no-841

be complete in 2033, after which the ADMS and OMS, which will be used to identify power outages quickly and precisely. After successful completion of the OptimizEV pilot, the Companies will evaluate potential OptimizEV scenarios.

Grid Automation: Grid automation future activities are discussed below.

> SCADA/Automation Program: The Companies will continue to make progress on their substation modernization upgrades.
>
> The Line Sensors Program is providing the Companies with partial ADMS and AGR deployment until the full substation modernization program is complete.
>
> Line Automation: As mentioned, substation and line automation devices are remote capable, connected with the ADMS through a telecommunications network to provide centralized coordination to monitor and control grid devices to ensure grid reliability.

The exhibit below shows the substation and line automation progress expected over the 2025 DSIP period.

EXHIBIT 2.3-2: GRID AUTOMATION COMPLETION RATES BY COMPANY

Counts by Company	Automated Device Counts (No.)					
	2023	2024	2025	2026	2027	2028
NYSEG						
SCADA/Automation Program*[19]	5	6	6	10	13	14
Line Sensors Program	0	0	500	600	0	0
Line Automation: Reclosers and Switches[20]	179	339	339	300	50	50
RG&E						
SCADA/Automation Program*[21]	3	5	2	11	12	13
Line Sensors Program	0	231	0	0	0	0
Line Automation: Reclosers and Switches[22]	48	26	58	125	125	125

[19] NYSEG has a total of 429 distribution substations.
[20] NYSEG has a total of 22,083 reclosers and switches.
[21] RG&E has a total of 156 substations.
[22] RG&E has a total of 5,798 reclosers and switches.

DER Management: To cost-effectively enable both beneficial electrification and rapid DER adoption in NY State, the Companies must be able to optimize the flows of both generation and load on the distribution grid through the management of DER. The Companies will utilize a centralized DERMS to monitor and control all types and sizes of DER including grid-scale PV, residential battery storage, smart thermostats, Electric Vehicle Supply Equipment, and building energy management systems. To provide optionality for customers and to account for the variance in capabilities inherent in the various technologies, the Companies will plan to utilize a variety of communication pathways and control strategies to manage DER including directly using DER Gateways communicating back to the centralize DERMS over utility-owned or leased telecommunication networks and via a utility-owned aggregation platform leveraging OEM APIs to monitor and control DER using both predictive and reactive signals. The Companies will continue to expand their existing DERMS capabilities starting in 2025 with the expansion of their FICS project to additional DERs, including electric vehicle charging sites. As part of this expansion the Companies will continue to develop their existing DERMS platform to provide additional functionality including Dynamic Operating Envelopes (DOEs), forecasting, and fail-safe schedules. This additional functionality will improve DER Management efficiencies by reducing curtailment, reducing risk, increasing reliability, and making it easier for Flexible DER to perform multiple grid functions. In the long-term, the Companies' DERMS platform will be able to utilize a model-based power flow to dynamically identify constraints at grid locations without direct metering and curtail and/or dispatch the correct DER to address the constraint. This future, model-adaptive, DERMS platform will be closely integrated to the Companies' ADMS to allow functions such as Volt-VAR Optimization or FLISR to account for and utilize DER in their control algorithms. Not all DER will be suitable to provide grid services as the safety and reliability of electric service to all electric customers will always be the number one operational priority and factors such as communications latency, response time, customer willingness, and the price of a particular service will all play a factor in the DERMS' optimization algorithms. The adoption of advanced DER Management strategies like Volt-VAR Optimization and FLISR will depend on the evolution of grid operational needs as DG penetration and electrification continue to increase and DER programs and markets develop. Overall, the Companies roadmap for DER Management will increase the amount of DER capacity that can interconnect to the grid while reducing the quantity and cost of the upgrades required to enable NY to reach its CLCPA goals, lowering the end cost to customers while maintaining or improving the Companies' current service standards.

<u>NYISO Coordination</u>: Through 2026, the Companies are working with NYISO and aggregators to synchronize data, as well as aggregate storage projects. The Joint Utilities will continue to coordinate with the NYISO in its 2023 DER market launch and the transition of Demand Side Ancillary Services Program ("DSASP") resources to the market between 2023-2025. Regarding the NYISO DER market timeline, in 2024, the NYISO will implement several software features that will help automate DERs and DER Aggregation participation. Over the 2025-2026 period, NYISO will implement the balance of software updates necessary for the fully compliant FERC Order 2222 market. These changes involve granular and complex changes to the NYISO's software to better automate, track, and audit DERs and DER Aggregation participation, and will be implemented no later than December 31, 2026. The Joint Utilities will continue to support NYISO's 2026 FERC Order 2222 market implementation and the potential for a more animated DER markets. Work to resolve previously identified and communicated short-term metering and billing limitations. The Joint Utilities will also refine processes for information and data exchange between the NYISO and the utilities and continue to evaluate alternative and lower cost forms of telemetry and communications for DER aggregations. The Joint Utilities also continue to identify framework(s) to recover utility costs for actions in support of the NYISO DER Market and its participants and continue to develop and monitor and scale, as appropriate, utility systems, processes, and roles to meet the needs of the DER market as it grows.

The exhibit below details our roadmap through 2030.

EXHIBIT 2.3-3: GRID OPERATIONS ROADMAP

Capability	Achievements (2023-2025)	Short-Term Initiatives (2026-2027)	Long-Term Initiatives (2028-2030)
Control Center Systems and Grid Optimization	• Upgrade OMS • Begin Operational Smart Grids (“OSG”) damage assessment and mobility alignment	• Complete OMS upgrade • Complete OSG damage assessment and mobility alignment	• Begin ADMS deployment
DER Management	• OptimizEV program offering • Demonstrate Flexible Interconnection Use Case (FICS REV Demo Phase 1) • “Pilot” DERMS: Standalone, centralized real-time dispatch schemes based on pre-defined relationships to grid constraints (Active Network Management)	• Demonstrate Non-Wires Alternatives Management Use Case • Expand deployment of Flexible Interconnections to additional grid locations • Expand deployment of Flexible Interconnection to Electric Vehicle Charging • “Flexible” DERMS: Standalone, centralized real-time and simplified forecasted DER dispatch for load, generation, and storage resources using Dynamic Operating Envelopes (DOEs) • DER gateway solution development for small and medium DER	• Long-term “DSO” DERMS: Powerflow model-integrated, centralized grid DERMS fully integrated with utility Edge DERMS • Procure Flexibility services based on forecasted and real-time grid needs • Orchestrate DER to mitigate curtailment and increase utilization factor of grid capacity
NYISO Coordination	• Begin data synchronization with NYISO and aggregators • NYISO DER-to-transmission node mapping • NYISO DER integration workflow • NYISO day-ahead data sharing requirements • NYISO metering and billing limitations development • DER aggregator information portal *(pending)*	• Complete synchronization with NYISO and aggregators, and establish process to maintain resource data synchronization with the NYISO and aggregators • DSASP Transition • NYISO automation and FERC Order 2222 software updates • Low-cost telemetry and communications evaluation • Develop cost recovery framework development, grow utility systems • ECC communications link with aggregators • FERC Orders 2222 and 841 compliance and tariff changes	• NYISO DER market launch Fully compliant FERC Order 2222 rules

<u>Integrated Implementation Timeline</u>: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period

ending in 2030. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

See Exhibit 2.3-3 above for the Companies' updated roadmap.

Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

Risk categories for Grid Operations developments remain the same as for 2023. However, the Companies have taken mitigation measures to address key risks.

Technology obsolescence: The Companies continue adherence to open standards and operability in carrying out the automation and AMI programs, as mentioned earlier. The Companies continue to develop pilots on new technologies and incorporate cost-effective and successful pilots when appropriate to ensure an 'evergreen' platform.

Technology deployment: The Companies continue to leverage global platform architecture and expertise, drawing on sister companies for experience on pilots, processes, and technology deployments.

Data and data security: The Companies have made progress on the GMEP and IEDR. The Companies continue to adapt plans based on lessons learned.

Operating as the DSO: The Companies continue to capture and apply lessons learned to apply at scale for all innovation and pilot projects.

EXHIBIT 2.3-4: GRID OPERATIONS RISKS AND MITIGATION MEASURES

Risk	Mitigation Measures
1. **Technology Obsolescence:** Grid Operations' efforts are particularly dependent upon a range of technologies deployed. Obsolete technologies can create significant barriers to integration due to proprietary interfaces and limited vendor support	• Adherence to open standards and interoperability where possible (*e.g.*, foundational investments, including automation and AMI, both incorporate these mitigation strategies). • Ensure 'evergreen' platform components where subsequent releases will include new functions and capabilities.
2. **Technology Deployment:** The integrated set of distribution systems and information technologies need to be correctly specified and then implemented according to plan, recognizing that regulatory actions (or inaction) will need to be managed. Most technologies rely on implementation of AMI and automation, which are foundational technologies.	• Master schedule and establish accountability. • Leverage global platform architecture and expertise, where applicable • Limit dependencies and deploy Minimum Viable Product (MVP) where necessary to meet Grid Operations needs while enabling technologies are deployed
3. **Data and Data Security:** DSO performance will depend on the quality and security of data that is relied upon by the DSO, third parties, and customers to make decisions.	• GMEP assessment to identify distribution assets on the system. • Corrections through GMEP will enhance reliability of asset data. • Redundancy built into AMI telecommunications infrastructure. • Maintenance of grid models to ensure data accuracy; model harmonization to establish common enterprise data model • IEDR provides an integrated model of the NYS electric distribution system • Provide flexibility in implementation to apply lessons learned and changing assumptions • Use of enterprise data lake as a repository and hub for IEDR data and other sharing requests • Increased use of search tools to leverage data in the data lake

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category's needs will be met over time; Describe and explain the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

DSIP stakeholders can be broken up into 4 groups:

a. **Consumers** – Customers that want to purchase electricity simply and easily as they do today. The goals and needs of consumers in Grid Operations are identified through the Companies Rate Case proceedings and various regulatory proceedings related to Grid Operations topics such as EV Managed Charging primarily through the participation of advocacy groups.
b. **Participants** – Customers who are interested in accessing additional economic value by managing their energy usage with technologies and/or behavioral changes. The goals and needs of Participants in Grid Operations are identified through the Companies Rate Case proceedings and various regulatory proceedings related to Grid Operations topics such as EV Managed Charging primarily through the participation of advocacy groups.
c. **Service Providers** – Customers that provide energy services to other customers such as developing DERs or owning and operating electrification infrastructure. The goals and needs of service providers in Grid Operations are identified through Working Groups such as the ITWG and IPWG, regulatory proceedings, Rate Cases, and dedicated topical workshops.
d. **Regulatory Bodies and Independent Market Entities** – The goals and needs of Regulatory Bodies and Market Entities are identified primarily through Working Groups such as the ITWG, IPWG, and JU ISO-DSP Coordination Working Group

The needs of all Stakeholders are gathered and incorporated into the Companies' DSP strategy for Grid Operations described in this section. The process of incorporating and updating the DSP strategy to reflect the changing needs of Stakeholders is an on-going process as feedback is received from the various Stakeholder groups. This DSP strategy is then used to write and update the Companies' DSIP filings every 2 years as well as more topic specific filings in the various regulatory proceedings active at a time such as the CGPP. As an example of how the Companies carry out Stakeholder Engagement for Grid Operations, the Companies held a dedicated topical workshop on Flexible Interconnection with DER Developers, DER Owners, DPS Staff, and other Industry Experts (EPRI and NY-BEST) in conjunction with National Grid in November 2024. At the meeting the Companies presented their experiences with Flexible Interconnections to-date and plans for expansion of their Flexible Interconnection offering and gathered feedback from the invited Stakeholders. Following the workshop, the Companies made changes to their Revised FICS REV Demo Implementation Plan in response to feedback received at the workshop.

EXHIBIT 2.3-5: STAKEHOLDER INVENTORY

Need	Stakeholder Group	How the Need Will Be Met and Estimated Time When Need Expected to be Met
1. **Flexible Interconnections:** Interconnection arrangements enabling more DER capacity to interconnect to the electric grid by utilizing utility-owned and operated real-time DER control schemes to automatically manage Distributed Generation and/or Distributed Storage outputs to stay within grid constraints **(For DER greater than 50 kW)** a) Distributed Generation and Storage b) For Electric Vehicle Charging c) For Other Loads	Participants Service Providers	• The Companies have implemented a DERMS system capable of managing simple Flexible Interconnections for Distributed Generation and Storage as part of Phase 1 of the FICS REV Demo. Deployment of Flexible Interconnections is currently limited to 3 participant sites, but the Companies have plans to expand the deployment to 3 additional substations in Phase 2 of the FICS REV Demo in **2026 (1a).** After gaining more experience with Flexible Interconnections in Phase 2, the Companies plan to explore expanding the offering to additional substations by **2029 (1a).** The timeline for expanding the Companies' Flexible Interconnection offerings is heavily dependent on regulatory support from the Commission including timely recovery of costs. • The Companies have plans to expand their Flexible Interconnection offering to include 2 electric vehicle charging sites in Phase 2 of the FICS REV Demo in **2026 (1b).** After gaining more experience with Flexible Interconnections for EV charging, the Companies plan to explore expanding the offering to additional customers, including other new loads, by **2027 (1b and 1c).**

Need	Stakeholder Group	How the Need Will Be Met and Estimated Time When Need Expected to be Met
2. **NWAs and Beneficial Locations:** Dispatching procured DER to address system needs. NWAs generally require compensating the participating DER(s)[23] a. **Automated Real-Time NWA Dispatch** b. **Short-Term NWA Dispatch Forecasting**	Participants Service Providers	• The Companies will complete testing and commissioning of the Stillwater NWA project into their existing Strata Grid DERMS in **2025.** The control scheme implemented will utilize a Dynamic Operating Envelope (DOE) to automatically dispatch the BESS when the Stillwater substation transformer bank is near its thermal limits and provide a forecasted dispatch schedule on a 24 hour ahead rolling basis **(1a and 1b)**
3. **Improved and Resiliency:** Utilize Grid Automation and ADMS investments to reduce the frequency and duration of outages a. **Substation and Line Automation** b. **FLISR**	Consumers Participants Service Providers Regulatory Bodies and Market Entities	• The Companies are in the process of modernizing their distribution substations and distribution line devices to provide enhanced monitoring, control, and protective capabilities. • NYSEG has deployed AGR/FLISR on 42 of its distribution feeders **(1b)**. As the level of grid automation on the Companies' grid increases, FLISR will be expanded to additional feeders and locations. • After the Companies deploy an ADMS by **2033**, they will enable more advanced FLISR algorithms to account for load masked by DERs **(1b)**
4. **Physical and Cyber Security:** Protect physical and cyber assets from external threats including threats from Nation States	Consumers Participants Service Providers	• Physical and Cyber Security are integral to all activities of the DSO and stakeholder needs in this area must be met continuously as new Grid Operations technologies and functionalities such as ADMS, DERMS, and Grid Automation are implemented from **2030-2034 (4)** • Responding to new and evolving threats is an on-going process requiring the Companies to explore and adopt new and innovative security technologies and approaches **(4)**
5. **NYISO-DSP Coordination:** Coordinate NYISO (wholesale)	Service Providers	• The Companies will continue to support NYISO's DER Market Launch

Need	Stakeholder Group	How the Need Will Be Met and Estimated Time When Need Expected to be Met
and DSP (distribution) market signals and operations **a. Support NYISO DER Market Launch** **b. Fully Implement FERC Order 2222**	Regulatory Bodies and Market Entities	throughout **2025 (5a).** Primary activities include evaluating DER Aggregations that apply to participate in the NYISO DER Market to ensure that no distribution constraints will result from NYISO dispatch events. • As NYISO rolls out their fully FERC Order 2222 compliant DER Market by the end of **2026 (5b),** the Companies will continue to support and refine processes for data sharing and explore lower cost DER M&C solutions

Stakeholder-provided information, capabilities, and actions are fundamental to the Companies' vision for Grid Operations as the DSO.

EXHIBIT 2.3-6: STAKEHOLDER-DATA NEED

Data Need	Frequency	Stakeholder Group	Implementation and Operational Outcomes
• **Basic DER Data** • DER Location • DER Size • DER Equipment Installed • DER Settings • DER Planned Import/Export Schedule	At Interconnection Application submittal and then by exception after	Participants Service Providers	• To account for DER in Grid Operations, the Companies must be aware of the basic details of all DER that plan to operate in parallel with and are connected to its system regardless of size • This DER Data allows the Companies to forecast the impact of DER on the grid with greater accuracy, enabling more advanced Grid Operations strategies that can increase grid efficiency such as Volt-VAR Optimization or Optimal

[23] Generally what separates NWAs from Flexible Interconnections is that DERs participating in NWAs are not contributing to the system issue that they are receiving compensation to solve

Data Need	Frequency	Stakeholder Group	Implementation and Operational Outcomes
			Feeder Reconfiguration
• **DER Operational Data** • DER Operating Mode • DER Import/Export • DER State of Charge (SoC) (ESS and EV-only) • DER In-Service/Out-of-Service	Regularly agreed intervals[24]	Participants Service Providers	• To integrate DER into Grid Operations, the Companies must be aware of the DER's current operational state[25] • This applies to all DER that wish to provide services to the grid in exchange for compensation in the form of demand response, NWAs, or a Flexible Interconnection
• **Planned Market Dispatch Schedule of Distribution Resources**	Daily	Regulatory Bodies and Market Entities	• To ensure that all conflicts between distribution and wholesale needs are addressed as quickly as possible, it is critical that the Companies are notified of the planned dispatch schedule of distribution connected resources

[24] Generally, the more frequently this operational data can be updated the better, particularly for larger sites (≥500 kW). Minimum frequency is every hour for less critical applications, but the standard is every 6s for critical applications. The Companies may require more frequent data sharing depending on the use cases envisioned.

[25] For less critical applications assumptions can be utilized in place of real-time telemetry as long as appropriate measurement and verification of resource performance is performed promptly after the event.

EXHIBIT 2.3-7: STAKEHOLDER- CAPABILITY NEED

Capability Need	Stakeholder Group	Implementation and Operational Outcomes
• **Quickly and reliably respond to control signals**	Participants Service Providers	• For DERs to provide the greatest value to Grid Operations, they must be able to be relied upon to provide the required response • To provide certain grid services, DERs must be able to respond rapidly with no or very little warning
• **Integrate with utility control systems utilizing industry standard control protocols**	Participants Service Providers	• Use of industry standard control protocols such as DNP3, Modbus, or IEEE 2030.5 helps expedite the DER monitoring and control integration process by leveraging existing utility expertise in and hardware that supports these standard protocols
• **Integrate with utility control systems utilizing utility specified standardized points list**	Participants Service Providers	• Utilizing a standardized points list limits the need for customer integrations and enables a diverse selection of services without requiring re-configuration

EXHIBIT 2.3-8: STAKEHOLDER- ACTION NEED

Action Need	Stakeholder Group	Implementation and Operational Outcomes
• **Continue Adoption and Deployment of DERS**	Participants Service Providers	• The Companies' Grid Operations Roadmap depends on customer adoption of solar PV, energy storage, electric vehicles, smart thermostats, smart panels, electric heat pumps, and other DER technologies • To utilize DERs as a resource for Grid Operations, a critical mass of adoption is required to achieve the required quantity of response

Action Need	Stakeholder Group	Implementation and Operational Outcomes
• **Remove regulatory barriers to the adoption of new Grid Operations strategies such as Flexible Interconnection and Flexibility Service Markets**	Regulatory Bodies and Market Entities	• To enable new DSO approaches and value sharing strategies by allowing DERs to actively participate in Grid Operations

The Companies utilize a variety of means and methods to effectively inform and engage associated stakeholders as the planning, design, and implementation of the functions and capabilities in this section progress. These communication and engagement channels include: working groups, workshops, regulatory filings, Bi-Annual Stakeholder Webinars, DSP Quarterly Newsletters, press releases, and surveys.

- **Working Groups** – The Companies participate in a variety of stakeholder Working Groups as part of the JU. Working Groups that address topics relevant to Grid Operations include the Electric Vehicle Infrastructure Interconnection Working Group (EVIIWG), ITWG, IPWG, and ISO-DSP Working Group. These Working Groups provide on-going collaborative forums where stakeholder engagement and feedback can be conducted as needs arise. Grid Operations topics covered in these Working Groups include Flexible Interconnections, DER Monitoring and Control, FERC Order 2222, and UL 1741 SB Compliance
- **Workshops** – The Companies participate in dedicated topical workshops as needed both independently and as part of the JU. Workshops enable the Companies to have more extensive discussions, involve internal and external topic-specific SMEs, and gather feedback from Stakeholders quicker and in a more targeted manner than would be feasible through Working Group discussions. The Companies also utilize workshops for topics where Stakeholder Engagement is needed that may be too specific to warrant a dedicated on-going working group on the topic and that may fall outside the scope or expertise of existing working groups. The Companies held a workshop on Flexible Interconnection in November 2024 in partnership with National Grid
- **Regulatory Proceedings** – The Companies participate in a variety of Regulatory Proceedings relevant to Grid Operations. These relevant proceedings are shown in the exhibit 2.3-8 below.

EXHIBIT 2.3-9: RELEVANT PROCEEDING

Regulatory Proceeding	Proceeding Name
• **14-M-0101**	Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision ("REV")
• **16-M-0411**	In the Matter of Distributed System Implementation Plans ("DSIP")
• **18-E-0130**	In the Matter of the Deployment of Energy Storage Deployment Program
• **18-E-0138**	Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure
• **22-E-0317**	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service.
• **22-E-0319**	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Electric Service
• **22-E-0549**	In the Matter of the Federal Energy Regulatory Commission (FERC) Order Nos. 2222 and 841
• **22-M-0149**	Proceeding on Motion of the Commission Assessing Implementation of and Compliance with the Requirements and Targets of the Climate Leadership and Community Protection Act (CLCPA)
• **23-E-0070**	Proceeding on Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure
• **24-E-0165**	Proceeding on Motion of the Commission Regarding the Grid of the Future
• **24-E-0364**	Proactive Planning for Upgraded Electric Grid Infrastructure

- The Companies' participation includes formal filings in the docket of each proceeding (such as this DSIP) and technical conferences. Both regulatory vehicles facilitate the Companies to disseminate their Grid Operations plans and strategies as they pertain to the topic of the given proceeding and receive feedback from stakeholders.
- **Bi-Annual Stakeholder Webinars** – The Joint Utilities hold a Stakeholder Webinar twice a year to present up-to-date material on JU progress on a variety of relevant topics and give stakeholders the opportunity to ask questions of utility SMEs.

- **DSP Quarterly Newsletters** – The Joint Utilities release a quarterly newsletter to present new developments in Grid Operations and other topics to stakeholders on an on-going basis.
- **Press Releases** – The Companies issue Press Releases to announce important milestones in the implementation of the capabilities discussed in this and other sections of the DSIP. As an example, the Companies issued a Press Release in August 2024 announcing the filing of the Intermediate Summary Report of their FICS REV Demonstration Project.[26]
- **Surveys** – The Companies utilize surveys as a tool to engage Stakeholders both in-conjunction with other engagement methods presented here, for example the short survey the Companies conducted with attendees of the Flexible Interconnection Stakeholder Engagement Workshop, and as the primary method for stakeholder engagement on a topic, for example the survey of FICS REV Demonstration Project participants
- To ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems, the Companies utilize the Stakeholder Engagement strategies presented in this section on an on-going basis and incorporate it back into their Grid Operations strategy. Where the Companies identify a gap in the alignment capabilities and stakeholder needs, the Companies convene internal stakeholders to identify how plans can be modified to develop the additional capability required to meet stakeholder needs.

The Companies continue to be engaged with various Joint Utilities working groups including the Independent System Operator-Distribution System Platform ("ISO-DSP") Coordination Working Group

The Companies continue to actively participate in the Joint Utilities-NYISO ISO-DSP working group. Complex changes are necessary to achieve market animation and to realize the coordination of the Utilities' planning and operating processes with related processes at the NYISO. New York's distribution utilities are critical partners in this process, as resources located on the local distribution system will now be participants in NYISO's wholesale markets. As such, the Joint Utilities have identified several issues to be addressed through a multi-lateral stakeholder engagement process prior to the implementation of FERC Order 2222. These issues include registration and enrollment of resources and aggregations, operational coordination and metering, telemetry, and

[26] NYSEG and RG&E Demonstrate Ability to Add Renewable Energy onto Grid with Flexible Interconnections - RGE

settlements. The Joint Utilities have taken and continue to take a four-pronged approach to working with stakeholders on these questions.

- First, the Joint Utilities are collaborating with the NYISO to implement the NYISO participation model for DERs. NYISO and the JU held regular technical working groups in 2021 to collaborate and compare system requirements. Together, the Joint Utilities and NYISO have initiated a series of workshops with the NYISO, New York Transmission Owners ("TOs"), and DPS Staff to document the processes and procedures required within existing and new NYISO guidelines. The first of these workshops was held in March of 2022 and workshops continue to this day on a twice-monthly cadence.
- Second, the Joint Utilities have initiated separate discussions with Staff to develop certain processes – such as a Commission process for resolving disputes pertaining to DER registration – that require collaboration.
- Third, to ensure that the input of the DER community is appropriately heard and addressed, the Joint Utilities have hosted workshops. The workshops provide a venue (with NYISO/DPS participation) for a productive dialogue on utility processes and procedures related to DER integration in the NYISO's wholesale markets. These have included:
    - On **April 29, 2022**, the Joint Utilities hosted a stakeholder workshop with the Aggregator community and other interested parties to review the distribution utilities' plans to support the implementation of the NYISO's DER Participation model, including the FERC Order 2222 tariff revisions.
    - On **August 30, 2022**, the Joint Utilities hosted a stakeholder session to review the telemetry requirements for communication between Aggregators and DU/TOs regarding the implementation of the NYISO's DER Participation model.
- Fourth, the JU have continued to remain active participants in the NYISO's stakeholder forums, including the Installed Capacity Working Group and Market Issues Working Group.

Additional Detail

The utility must enable a much more dynamic, data-driven, multi-party mode of grid operations where DERs effectively generate customer value by increasing efficiency, stability, and reliability in both the distribution system and the bulk electric system. To achieve this outcome, the utility must develop and/or substantially modify a wide range of components encompassing operating policies and processes, advanced information systems, extensive data communications infrastructure, widely distributed sensors and control devices, and grid components such as switches, power flow controllers, and solid-state transformers.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to the utility resources and capabilities needed to transform grid operations in both the distribution system and the bulk electric system:

1. *Describe in detail the roles and responsibilities of the utility and other parties involved in planning and executing grid operations which accommodate and productively employ DERs.*

   Our primary responsibility is to maintain distribution system safety, security and reliability. The Joint Utilities have coordinated with DER aggregators and the NYISO to define operational coordination requirements, including specific roles and responsibilities for each party, to ensure that we can continue to preserve safety and reliability for a system experiencing increasing numbers of DER. As part of our various utility programs (*e.g.*, demand response) and procurements (*i.e.*, NWA), NYSEG and RG&E require DER aggregators and other third-party market participants to execute agreements that define our respective roles and responsibilities.

   In addition to our role as the DSO, the major parties involved in performing Grid Operations and integrating DERs are our ECCs, the NYISO, aggregators, and DER customers.

   <u>ECC</u>: Our ECC serves as the distribution grid operator. The ECC is responsible for the operation of the utility grid by monitoring and responding to changing network conditions, utilizing grid-side, supply-side, and demand-side resources as well as responding to customer trouble and outages. ECC operators maintain distribution system voltage and the DERs connection to the distribution system. The ECC will require new tools and more granular grid visibility to dispatch DER. The ADMS will act as the "core" advanced technology that integrates multiple systems to automate grid functions including outage restoration and grid optimization. The ADMS provides ECC operators with tools to verify the state and security of the distribution grid, allowing them to incorporate DERs into short-term forecasting and other operations. The ADMS will also support additional layered capabilities, such as the DERMS, which ECC operators will use to manage the entire fleet of connected DERs (including distributed generation, energy storage, and demand response). This facilitates the management, optimization, and dispatch of DERs to secure the grid. The ECC will rely on these technologies to improve network performance through automation and efficiency gains. In the longer term, ECCs will incorporate the use of a DER Market Management System to support future markets with development of these systems occurring after the market design is defined.

NYISO: The NYISO operates the wholesale market and performs planning and operation of the bulk power system. Increasing DER penetration will require greater coordination and communication between the DSO and the NYISO. The DSO will work with the NYISO in establishing an interface definition between the two entities for effective distribution network management, including data requirements, communication and coordination, activation of DER, and mechanisms for DER aggregation. Our DER Attribute Database will compile attributes of DERs necessary for dispatching and interfacing with NYISO, as well as forecasting and outage scheduling. Our ECC and planning engineers will work with the NYISO for day-ahead, short-term, and long-term planning that affects the transmission grid and for resolving unplanned events.

Aggregators: An aggregator bundles individual DERs from multiple customers, which can then be managed collectively to provide energy, capacity, or other services. Third-party aggregators will need to coordinate with our ECC and our energy supply function to manage these resources, which can be used for many functions including solutions that reduce energy usage during periods of peak demand.

DER Owners and Operators: DER owners and operators will increasingly be able to provide benefits and risk to the grid, and will become key players as the distribution network gains more granular monitoring and control and the ability to integrate these assets. To facilitate this integration, our DERMS will analyze available DERs and will dispatch or curtail it as needed. DERMS will also have the flexibility and scalability to interact with multiple aggregators and customers for DER-sourced voltage support.

The Joint Utilities have developed a *Draft DSP Communications and Coordination Manual* to define the roles and responsibilities among the utility, the NYISO, DER aggregators, and individual DERs to enable DERs wholesale market participation while preserving system safety and reliability.[27] For example, as part of the NYISO's bidding and scheduling process, the DSO/DSP will analyze the dispatch feasibility of individual DERs and DER aggregations (as provided by the DER aggregator) to ensure wholesale market participation does not jeopardize distribution system safety or reliability. The Joint Utilities have also developed a *Draft DSP-Aggregator Agreement for NYISO Pilot Program* to further define the roles and responsibilities between the DSO/DSP and DER aggregators.[28]

Deployment of technology platforms, including the ADMS and the DERMS, will provide the DSOs with the ability to analyze and manage DER assets. We anticipate the deployment of these technologies will be implemented in phases. While technically possible, it will be a challenge to retrofit to obtain monitoring and control capabilities for all DER, particularly if the coming market design does not provide the appropriate incentives to retrofit. Ideally, the upcoming Market Design and Implementation Plan will provide incentives for DERs to provide distribution grid services. New technologies and architectures for Enhanced DERs M&C will enable this participation.

The DSOs can also use these technology platforms to coordinate with the NYISO and third-party stakeholders to manage local DERs in order to benefit the local distribution system and provide a pathway for these local assets to participate in the NYISO wholesale markets.

2. *Describe other role and responsibility models considered and explain the reasons for choosing the planned model.*

We plan to integrate the EMS and Data Management System ("DMS") housed within a single Physical Security Perimeter ("PSP") and Electronic Security Perimeter ("ESP") to facilitate system integration and to minimize support requirements, as well as to maximize both cyber security and physical security of these systems. We are implementing a single ECC model to facilitate T&D coordination. We also chose our GIS to be the source of the grid model for both DSO ISP and Grid Operations to maintain synchronization of the model between planning and operations and provide a single accurate data source of record for all business functions. The role of the distribution operator is evolving at NYSEG and RG&E and we will update switching authority and operating procedures to advance the appropriate roles and responsibilities in a safe

[27] Draft DSP Communication and Coordination Manual available at https://jointutilitiesofny.org/sites/default/files/JU_DSP_Comms_Coordination_Manual_DRAFT_2.pdf

[28] Pilot program agreement available at https://jointutilitiesofny.org/sites/default/files/Draft_JU_DSP_Aggregator_Agreement_NYISO_Pilot_Program.pdf

manner. RG&E is currently the switching authority while NYSEG has initiated pilot programs to transfer Distribution Grid Operating Authority from de-centralized to centralized operations.

NYSEG has also successfully hired enough operators to provide 24/7/365 operations from the ECC. As of 2024, NYSEG has utilized NYSEG distribution operators to perform remote switching for field operators in all of its 13 divisions. This is a fundamental shift in operating procedures for NYSEG and requires extensive training for field and ECC personnel, along with ensuring accuracy of mapping, prints, and equipment inventory to be fully verified and updated as needed.

Due to the Companies' obligation to provide safe and reliable electric service to all customers, the only possible role and responsibility model is one where NYSEG and RG&E is the DSO.

3. *Describe how roles and responsibilities have been/will be developed, documented, and managed for each party involved in the planning and execution of grid operations.*

We expect to continue to develop and refine the roles and responsibilities for parties that contribute to Grid Operations by documenting lessons learned through technology project implementation in the Energy Smart Community and by continuing to collaborate with these parties and interested stakeholders. For example, the deployment of the ADMS and DERMS platform within the ESC will allow our ECC to monitor and control DERs on a more granular level.

We will continue to work with the Joint Utilities and the NYISO to define and refine all roles and responsibilities, proactively implement standards and protocols, and streamline processes (*e.g.*, vendor prequalification) to ensure continued safe and reliable operations as DERs comprise an increasing share of generation. While the high-level roles and responsibilities will generally be consistent across our programs and procurements, the unique characteristics of each utility may result in differences (*e.g.*, pre-defined time periods in which the DER portfolio is required to be available for performance). In addition, as the DSO, we expect to provide the distribution-level functions that the NYISO performs at the transmission level. A significant DSO function that needs to be developed will include dispatch of individual DER. Relevant parties, including the DSO, the NYISO, DER operators, and aggregators will require synchronized resource data and multiple real-time communication flows in order to collectively ensure a reliable and secure grid. Integrating DER cyber security protocols will likely be a complicated, costly, and time-consuming effort, as such protocols will need to be developed and implemented throughout the industry.

Grid operations will continue to be responsible for the safe, reliable, secure, real-time operations of the electric distribution system within the Companies' footprint. Grid operations will continuously monitor the state of the distribution system, manage planned and unplanned outages, and optimize the system to achieve cost, environmental and reliability objectives.

With the ongoing transition to a system with high penetration of DER, the Companies anticipate that new capabilities in operational distribution planning will be required to support Grid Operations. These capabilities will include analysis and short-term planning of the electric distribution system with the primary objective of supporting Grid Operations in providing real-time grid services for existing load and distributed generation. Grid Operations will be increasingly involved in evaluating and integrating DERs as part of an optimized T&D system. It will also be important to expand Grid Operations capabilities to include the registration, monitoring, management, coordination, and optimization of numerous DERs to support grid operations, and potentially provide grid services. With the ongoing transition to a system with high penetration of DER, the Companies anticipate that new capabilities in operational distribution planning will be required to support Grid Operations. These capabilities will include analysis and short-term planning of the electric distribution system with the primary objective of supporting Grid Operations in providing real-time grid services for existing load and distributed generation. Grid Operations will be increasingly involved in evaluating and integrating DERs as part of an optimized T&D system. It will also be important to expand Grid Operations capabilities to include the registration, monitoring, management, coordination, and optimization of numerous DERs to support grid operations, and potentially provide grid services.

The Companies plan to develop and refine these capabilities as platform technologies are implemented and can be utilized to manage an increasingly complex distribution system.

4. *Describe in detail how the utilities and other parties will provide processes, resources, and standards to support planning and execution of advanced grid operations which accommodate and extensively employ DER services. The information provided should address:*

a. *organizations.*

A common set of protocols is required to implement the advanced capabilities to perform as the DSO. We have been coordinating with several organizations (*e.g.*, NYISO, FERC, aggregators, Community Choice Aggregation ("CCA") administrators, NYSERDA, Electric Cooperatives, vendors and contractors) to develop and refine Grid Operations processes and standards to support DER deployment. Successful DSO implementation will hinge upon coordinating with the parties listed in Subpart 1, as well as the FERC to provide input and feedback on developing operating standards.

We described our participation in Joint Utilities working groups in addressing Stakeholder Interface above.

b. *operating policies and processes.*

As discussed above, we continue to develop and refine operating policies through coordination with parties that contribute to Grid Operations and apply processes and standards through testing of new technologies in a series of innovation projects. We are developing policies and processes through coordination with the Joint Utilities and NYISO, as well as our own utility-specific requirements. See the *Stakeholder Interface* section above for more details on Joint Utilities' developments and collaboration with NYISO over the past two years. We continue to review and update operating instructions and procedures to ensure compliance with our current operating practices. We are also in the processes of working with PolicyTech to improve our operating instructions and procedure reviews, storage and accessibility.

The Companies continue efforts to update our connected DER database and improve the quality and granularity of load data that will be utilized to perform interconnection studies, where such studies are required.[29] In addition, NYSEG and RG&E follow IEEE[30] standards and protocols on DER dispatching and integration, including IEEE-

[29] See 2.11 (DER Interconnections) for more details on the Companies interconnection policy developments. See 2.2 (Advanced Forecasting) for additional details on our approach to DER forecasting.

[30] IEEE is a professional association that provides electrical standards that are applied to a number of industries.

2030.5,[31] IEEE-2030.7,[32] and IEEE-1547.1.[33] We will adopt additional protocols as appropriate.

c. *information systems for system modeling, data acquisition and management, situational awareness, resource optimization, dispatch and control, etc.;*

The Companies are developing several Grid Operations technologies to support situational awareness, optimize resources, develop more granular dispatch and control of resources, and provide data for system modeling. We will deploy these technologies in a staged manner, as explained in the *Future Implementation and Planning* section above.

d. *data communications infrastructure;*

A telecommunications network is required to support both AMI and Grid Automation. Both projects require the telecommunications network to securely transmit data and interact with field devices. The network includes diverse communications solutions (*e.g.*, radio frequency, cellular data, microwave frequency, fiber optics, leased circuits) and will allow remote access and control of devices on the grid. The network will also transmit data on the performance of installed DERs and support our DR programs.

Finally, the telecommunications network allows us to communicate with Remote Terminal Units and other relay equipment at substations, providing better visibility into substation operations, and provide real-time situational awareness that can reduce outages and improve response time.

We are building an AVANGRID-wide telecommunications infrastructure. This involves the strategic addition of fiber optic, microwave links, and digital radio capability, depending on security and cost effectiveness of each application. Additionally, the Companies plan to construct towers to support radio frequency communication with the ECC from remote locations.

In support of AMI, we are continuing to engineer, procure, and construct a telecommunications network across the territories to support automation and AMI efforts. As a common network is deployed, additional nodes and services can be added with minimal incremental cost. We plan to work with telecommunications

[31] IEEE 2030.5 is a standard for communications between smart grids and consumers, giving consumers a range of methods to manage energy use and generation. Information exchanged via the standard includes demand response, pricing, and energy usage, enabling integration of smart devices, such as thermostats, meters, electric vehicles, smart inverters, and appliances.
[32] Governs microgrid controllers.
[33] IEEE-1547.1 governs smart inverter communications.

providers to determine the most cost-effective approach to achieve our objectives. These communication links are vital to realizing the benefits of automating our substations and distribution system.

e. *Grid sensors and control devices*

Grid automation will support installation of grid sensors and control devices to support a range of functions, including VVO, feeder optimization, and FLISR. Grid Automation equipment is comprised of load-tap-changers ("LTCs"), breakers, reclosers, regulators, capacitor banks, switches, and supporting telecommunications networks that allow us to manage and optimize power flows on circuits in response to changing system conditions and events.

In the short and medium term, the focus will be to continue to automate reclosers, tie switches, and sectionalizing switches to better optimize feeder configuration and outage management by improving system resiliency and customer reliability. In the long term, we anticipate having all distribution control devices automated including capacitors, LTCs, and voltage regulators. Integration of systems and field devices will further enable improved reliability through FLISR and improved efficiency with the integration of end-of-line AMI voltage data to enable VVO capabilities.

f. *grid infrastructure components such as switches, power flow controllers, and solid-state transformers;*

The Companies plan on utilizing switches as presented in the section above. Additionally, the use of power flow controllers is being explored as to applicability on the electric system. Power flow controllers have the potential to accommodate the interconnection of additional DERs without the need for system upgrades in certain constrained areas of the electric system. The Companies are also exploring dynamic line ratings to increase asset utilization which can also increase the amount of interconnected DERs in thermally constrained areas.

5. *Describe the utility's approach and ability to implement advanced capabilities:*

See discussion of Advanced Metering, Grid Automation and Management, and DER Integration above.

a) *Identify the existing level of system monitoring and distribution automation.*

See Exhibit 2.3-3 above.

b) *Identify areas to be enhanced through additional monitoring and/or distribution*

automation.

See Exhibit 2.3-3 above.

c) *Describe the means and methods used for deploying additional monitoring and/or distribution automation in the utility's system.*

See Grid Automation deployment plan above.

d) *Identify the benefits to be obtained from deploying additional monitoring and/or distribution automation in the utility's system.*

The Companies are focused on implementing both general monitoring and control of the grid and DER-specific M&C. DER management and dispatchability will increase DER value as DER market participation grows. The ability to integrate DERs into grid optimization schemes provides the opportunity for these customers to participate in the ancillary services markets, providing additional value. In addition, M&C initiatives will assist in establishing an appropriate level of visibility, ensuring ongoing system safety and reliability as DERs become increasingly integrated and impactful to the grid. DER M&C allows the ADMS and DERMS to identify and address potential grid constraints before they occur and proactively optimize grid performance. In addition, DER M&C enables more DERs to interconnect by enhancing the accuracy of the assumptions made when study a DER's system impact and by allowing the Companies to identify and automatically address system constraints when they occur instead of requiring DERs to shoulder the cost of reinforcing the grid to account for conditions that occur for only a couple hours a year. In the end, effective M&C improves system efficiency, enhances grid resiliency, and improves customer satisfaction. In addition, increasing automation capabilities will provide more timely response to outages, more efficient Grid Operations through remote troubleshooting and analysis, reduced energy losses, and enhanced visibility, control, and optimization of DERs on the grid.

e) *Identify the capabilities currently provided by Advanced Distribution Management Systems (ADMS).*

See discussion of ADMS above.

f) *Describe how ADMS capabilities will increase and improve over time;*

See discussion of ADMS above.

g) *Identify the capabilities currently provided by DER Management Systems*

(DERMS).

The Companies deployed Smarter Grid Solution's (SGS) Strata Grid DER Management System as part of the FICS REV Demonstration Project. The Companies have been utilizing the SGS Strata Grid system in conjunction with SGS's Element Grid DER Gateway solution to operate a Flexible Interconnection scheme including three, 5 MW Solar PV sites on RG&E's Station 113. The Strata Grid solution enables the Companies to manage Flexible Interconnections by automatically curtailing participating DER sites when a potential grid constraint is observed. The Companies are also in the process of utilizing Strata Grid and an Element Grid panel to dispatch-the NYSEG NWA on Stillwater substation. The control solution for Stillwater will forecast future dispatch needs, create and send a rolling 24-hour "fail-safe" dispatch schedule, and utilize both a maximum discharge and a real-time maximum charge threshold, a "Dynamic Operating Envelope (DOE)", to control the operation of the NWA. The Companies plan to complete the integration of the Stillwater NWA scheme into the Strata Grid solution in 2025.

h) Describe how DERMS capabilities will increase and improve over time.

Over time, the Companies will continue to develop and refine the implementation of the Non-Wires Alternatives and Flexible Interconnection DERMS use cases as their deployment is expanded to additional locations throughout their service territory.

The Companies have identified several core functions that will be critical to providing more advanced NWA and Flexible Interconnection use cases in the future. These functions include:

- **Forecasting –** In order to optimize the utilization of DERs, the Companies must be able to accurately forecast DER output and grid conditions in the short, medium, and long-term. Forecasting also enables "smart" fail-safes which incorporate predicted grid conditions and needs into the fail-safe setpoint utilized by the DER in the case of loss of communications with the utility and dispatch of assets without real-time observability.
- **Group Management –** In order to safely and reliably perform Grid Operations functions with large amounts of aggregated DER, the Companies must be able to dynamically group the DER by any number of parameters. Examples of parameters that the Companies will need to be able to group are: grid topology (PTID, circuit, substation, voltage regulation zone), DER program, and availability. In addition to creating these groups of aggregated DERs, the Companies must be able to dynamically update and manage group membership as new DER come online, as existing DER enroll or unenroll in different DER Management programs, or as grid

configuration changes. Once these DER Groups are created and managed, they will be utilized for dispatch and control of the member DER for Flexible Interconnections and/or NWAs.

- **Distribution Power Flow –** While Distribution Power Flow is seen as a core capability of an ADMS, it will also be a necessary function for DER Management. A power flow model can be used to fill in gaps in real-time telemetry and when paired with forecasting it can be used to predict constraints on the distribution system ahead of time to give the DSO time to identify and dispatch other assets to avoid the predicted constraint. A distribution power flow model can also be used for contingency planning to determine what grid needs might arise in an N-1 or N-1-1 scenario.
- **Machine Learning –** Another solution to fill-in gaps in the distribution grid model that might inhibit distribution power flow modeling or to allow the Companies to perform State Estimation with limited real-time grid measurements is to utilize Machine Learning models trained on high resolution historical grid measurement data to predict the grid constraints that might be seen if certain conditions exist. This strategy can be utilized for both forecasted and near-real-time grid operation.

The deployment of these DERMS functions will depend on a variety of internal and external factors including, DER adoption, market development, regulatory mandates, data availability, and funding availability.

i) Identify other approaches or functionalities used to better manage grid performance and describe how they are/will be integrated into daily operations.

The Companies current DER Management platforms that serve Grid Operations use cases, sometimes referred to as “Grid” DERMS, are logically and operationally isolated from the Companies’ DER Management platforms, sometimes referred to as “Edge” DERMS, that serve Market Services use cases such as demand response and electric vehicle managed charging. This separation inhibits the Companies from utilizing DERs already enrolled and receiving signals from these Edge DERMS platforms for Grid Operations. In the future, the Companies plan to provide an interface between these two systems to facilitate this participation at the distribution level. Plans are to eventually create a logical interface between the Companies’ Grid and Edge DERMS’. Prior to designing and implementing this interface the Companies must conduct a comprehensive cyber and physical security readiness assessment of the risks introduced.

The Companies intend to utilize a market-based competitive approach to determine which assets utilized to meet each grid need wherever possible. To accomplish this, the Companies intend to build a DER Market Management Systems (DER MMS) to disseminate the grid needs, solicit grid service "bids" from third-party DERs, return the "bids" to the Companies' DERMS, receive the winning "bids" back from the Companies' DERMS, notify the participants of the results, and perform market settlement after verification has been received from the Companies' DERMS that service was provided. The Companies expect the solicitations carried out via the DER MMS will vary in time horizon from long-term (5 year+) ahead of when the need is expected to occur to day-ahead or even hour-ahead of the expected need. The deployment timeline for the DER MMS is still unclear, but the Companies expect that one of the outcomes of the Grid of the Future Proceeding[34] may be to provide clarity of when a DER MMS will be required to enable Flexibility.

[34] Case 24-E-0165, Proceeding on Motion of the Commission Regarding the Grid of the Future

2.4 Energy Storage Integration

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2023 DSIP Update filing.

Policies

Energy Storage Systems (ESS) continue to play an important role in the grid of the future, and increased ESS deployment is supported by both state and federal policy. At the state level ESS is supported by CLCPA goals and the Energy Storage Roadmap, while at the federal level ESS deployments benefit from the Inflation Reduction Act (IRA) and FERC Orders 841 and 2222. Since the 2023 DSIP filing, the Commission issued the Order Establishing Updated Energy Storage Goal and Deployment Policy on June 20, 2024 to support New York's 6 GW energy storage target[35]. In response, NYSERDA published implementation plans for the Residential, Retail, and Bulk Energy Storage programs. [36] These policy advancements will support further ESS deployment in New York.

ESS has multiple benefits to T&D system and overlaps with other policy goals in New York. In 2024, the Joint Utilities filed a Study of Non-Market T&D Energy Storage Use Cases and Related Process Proposals. [37] The Study identified six different applications where utility-owned ESS could provide services to the T&D system and proposed new processes for utility-owned ESS project approval and cost recovery. As of the drafting of this DSIP update, the Study is undergoing public comment and PSC review. Many of the energy storage applications on the T&D system support other policy goals, such as electrification and increased renewable energy deployment. These applications overlap with goals of other ongoing proceedings, such as the PSC's August 2024 Order Establishing Proactive Planning Proceeding.[38]

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[35] Case 18-E-0130, In the Matter of Energy Storage Deployment Program (Storage Proceeding), Order Establishing Updated Energy Storage Goal and Deployment Policy (issued June 20, 2024) (2024 Storage Order).

[36] Case 18-E-0130, In the Matter of Energy Storage Deployment Program (Storage Proceeding), NYSERDA Residential and Retail Energy Storage Market Acceleration Incentives 2024-2030 Implementation Plan (filed August 19, 2024) and NYSERDA Bulk Energy Storage Implementation Plan Proposal (filed October 18, 2024)

[37] Case 18-E-0130, In the Matter of Energy Storage Deployment Program (Storage Proceeding), Joint Utilities' Study of Non-Market Transmission and Distribution Energy Storage Use Cases and Related Process Proposals (filed October 29, 2024).

[38] Case 24-E-0364, *In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure*, Order Establishing Proactive Planning Proceeding (issued August 15, 2024).

Utility-scale battery storage continues to benefit from cost declines, as documented in NREL's 2024 Annual Technology Baseline [39]. However, battery suppliers are facing uncertainty with potential federal tariffs and counter-vailing duties, which may result in increased ESS costs in the short-term. Additionally, there is uncertainty over federal policy regarding the Investment Tax Credit (ITC) provisions of the IRA, which may also contribute to higher ESS development costs in the short-term.

Processes, Capabilities, & Resources

The Companies are pursuing the following high level energy storage goals:

- Utilize available NWA projects to deploy storage when ESS is the most cost-effective solution through 3rd party developer proposals.
- Develop and complete utility-owned storage projects in targeted areas of the system to address system reliability and resiliency needs
- Continue to propose utility-owned energy storage projects to further demonstrate the system benefits of non-market utility ownership
- Integrate storage into planning and operations processes to gain DSO operational experience to include energy storage as a business-as-usual asset

In support of these goals, the Companies continue to advance the two energy storage projects approved in the Companies' 2022 rate proceeding,[40] operate company-owned storage to provide ratepayer benefits, run bulk energy storage RFPs to solicit Utility Dispatch Rights ("UDR") storage projects, and evaluate NWA projects utilizing ESS when addressing system needs. The Companies have made improvements to related processes and capabilities, including advanced modeling of ESS benefits and estimating ESS project costs. In addition, the Companies have added resources in line with the Planned Incremental Resources detailed in the Companies' 2022 rate proceeding, with these

[39] NREL (National Renewable Energy Laboratory). 2024. "2024 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/.

[40] Cases 22-E-0317 et al, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service, Order Adopting Joint Proposal (issued October 12, 2023), Joint Proposal Attachment 1 – Appendix N: Battery Storage RFP Process.

resources supporting energy storage deployments and future projects/developments for ESS throughout the NYSEG and RG&E service territories.

As of February 27, 2025, the cumulative amount of ESS capacity interconnected in the Companies' service territories is greater than 69 MW for NYSEG and greater than 7 MW for RG&E. Of this ESS capacity, approximately 6 MW was interconnected since the date of the 2023 DSIP publication.

Standards

The Companies continue to advance internal standards for new ESS projects with a goal of following industry best practices that follows a comprehensive set of guidelines and protocols. These include compliance with the latest cybersecurity standards, covering device-level, network, and data security. Company ESS projects also follow a detailed Substation Standard, Quality Policies, and Health and Safety Requirements. Environmental management is conducted to ensure sustainable and responsible project execution.

Additionally, the Companies adhere or exceed Fire Protection ESS Standard and other relevant fire and explosion protection standards, ensuring all projects meet necessary certifications. The Companies' most recent Electrical Energy Storage System Standard compiles fire protection and safety best practices from around the industry as well as relevant codes and standards with the intent to protect lives, infrastructure, and the environment in the best ways possible. The Companies are also incorporating the recommendations from New York's Inter-Agency Fire Safety Working Group into these internal standards and processes, including following the Peer Review process administered by NYSERDA for new Company-owned ESS. [41] As fire protection technology advances and more systems and components become available, this standard will be revised periodically to reflect current best practices within the industry.

[41] New York's Inter-Agency Fire Safety Working Group, https://www.nyserda.ny.gov/All-Programs/Energy-Storage-Program/New-York-Inter-Agency-Fire-Safety-Working-Group

[Current Progress]{.underline}: Describe the current implementation as of June 30, 2025; describe how the current implementation supports stakeholders' current and future needs.

NYSEG and RG&E continue to make progress deploying energy storage projects and advancing their energy storage roadmap. The Companies continue to work with the Joint Utilities (JU) and the Advanced Technology Working Group (ATWG) to advance policies supporting energy storage deployment in their service territories. In addition, the Companies are working on several initiatives to support both utility-owned storage and third-party owned storage projects that interconnect to the Companies' system.

In June 2024, the NY PSC issued its Order Establishing Updated Energy Storage Goal and Deployment Policy which directed the Joint Utilities to study the non-market T&D services that energy storage can provide [42] NYSEG and RG&E worked with the Joint Utilities on the study, which identified six applications where utility integrated storage could support or provide T&D services [43]. These six applications include Flexible Transmission Capacity, Flexible Distribution Area Capacity, Distribution Resiliency and Reliability, Bridge-to-Wires (BTW), Large-Scale Renewable Enablement, and DER Integration and Hosting Capacity on Distribution Network. The Companies continue to evaluate utility-owned storage projects that fulfill one of these six applications. In addition to the study, the Companies worked with the Joint Utilities to support energy storage initiatives within the Energy Storage Task Force (ESTF) group of the ATWG. These initiatives are detailed within the ATWG 2024 Annual Report [44].

The exhibit below includes the Companies' current and proposed energy storage projects:

- Bulk storage Utility Dispatch Rights (UDR) solicitations
- NWA projects that include ESS
- Demonstration projects; and

[42] Case 18-E-0130, In the Matter of Energy Storage Deployment Program (Storage Proceeding), Order Establishing Updated Energy Storage Goal and Deployment Policy (issued June 20, 2024) (2024 Storage Order), Ordering Clause 20 at p. 96-97.
[43] Case 18-E-0130, In the Matter of Energy Storage Deployment Program (Storage Proceeding), Joint Utilities' Study of Non-Market Transmission and Distribution Energy Storage Use Cases and Related Process Proposals (filed October 29, 2024) at p.7.
[44] Advanced Technology Working Group (ATWG) 2024 Annual Report dated January 31, 2025, at p. 9-11. https://jointutilitiesofny.org/sites/default/files/2024%20ATWG%20Annual%20Report.pdf

- Proposed utility-owned storage.

Together, these projects total a minimum of 30.6 MW in potential storage capacity.

In addition to these energy storage projects, the Companies continue to advance efforts to support third-party owned storage projects throughout the service territories. The Companies' interconnection application for standalone ESS sized 5 MW and smaller now have specific requirements detailed in Appendix K. [45] The Companies continue to work with the IPWG and the ITWG to propose amendments to Appendix K and the NYSSIR to facilitate energy storage interconnections throughout the state. [46] These enhancements to the interconnections process support third-party storage developers in deploying projects throughout the Companies' service territories.

The Companies also continue to make updates to hosting capacity maps in support of energy storage deployments. The hosting capacity maps have been updated to provide nodal level energy storage hosting capacity (the previous version provided feeder level hosting capacity). This improves the information available to developers for evaluating potential locations for future storage projects. More information about the Hosting Capacity maps can be found in the Hosting Capacity section of the DSIP.

Storage projects within the Companies' service territories are able to take service under different portions of the Companies' rate tariff. Larger standalone storage projects may take service under the Standby Service rate to pay for imported energy related to battery charging, while smaller behind-the-meter storage projects pay for imported energy under the customer's applicable service classification in the tariff. Storage discharging is also compensated under different portions of the tariff, including options for exported energy to be compensated under the Buyback service classification or the Value Stack methodology included in the Companies' rules for VDER. These tariff provisions support further energy storage deployment, both for stand-alone and behind-the-meter storage installations.

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[45] NYSEG Appendix K (Energy Storage System (ESS) Application Requirements / System Operating Characteristics / Market Participation, https://www.nyseg.com/documents/40132/5899056/Appendix%2BK.pdf/f0d403b7-0d3c-57a1-0e49-54c4f4f981b2?version=1.0&t=1645136483515

[46] Case 24-E-0621, In the Matter of Modifications to the New York State Standardized Interconnection Requirements and Application Process for New Distributed Generator and/or Energy Storage, Petition of IPWG and ITWG Members Seeking Minor SIR amendments filed November 27, 2024

EXHIBIT 2.4-1 ENERGY STORAGE PROJECTS

Project	Status
Bulk Storage Projects	
Bulk Storage UDR Solicitations	NYSEG and RG&E continue to run RFPs to procure at least 10MW of bulk-connected storage for each Company to be in service by December 31, 2030. The companies completed three rounds of competitive procurements with no viable project awards (competitive procurement rounds completed in 2020, 2022, and 2023). The Companies recently released a fourth RFP on June 9, 2025 with expected responses due August 4, 2025.
NWA Projects	
Stillwater Storage Project	NYSEG 1MW / 2.9 MWh NWA project to address substation overload and low voltage power quality issues through developer-installed storage system located 1.8 miles from the Stillwater substation. NYSEG commissioned this project in November of 2023. NYSEG is working to connect the Stillwater ESS to the Strata Grid system to allow for automatic dispatch of the battery, which is expected to be complete in Q2 2025.
Demo Projects	
Aggregated Behind the Meter ("BTM") Energy Storage	NYSEG partnered with a third-party market partner to install six storage facilities of varying sizes on commercial and industrial customer sites in the ESC footprint. NYSEG installed a total of 765 kW / 3,080 kWh energy storage. We tested three use cases: customer energy demand management, aggregated demand response market participation, and circuit and system peak reduction. Two battery systems were installed by the end of 2018, and we installed another three by the end of the first quarter in 2020. The sixth and final site was completed in late 2020. One customer chose not to continue with the program and had the battery storage system removed from their site. The project team has successfully decommissioned, removed, and relocated the battery storage system from the Customer's site in 2021. The Company filed a Closeout Report for this REV demonstration project in Q2 2023 which included lessons learned from the project.
Integrated Electric Vehicle ("EV") Charging and Battery Storage System ("BSS")	RG&E installed the 150 kW / 600 kWh energy storage system in December of 2018 at our Scottsville Road Operations Center in Rochester. The purpose of this project was to demonstrate how battery storage could be integrated with EV charging to improve project economics, minimize the impact of EV charging on the grid, and derive value from market services by pairing an ESS with two EV DC fast chargers and five level 2 chargers. We tested three use cases: building / circuit demand reduction, building load factor improvement, and demand response. By addressing the building load and DC fast charger load through battery optimization, we are relieving the circuit demand. The Company filed a Closeout Report for this REV demonstration project in Q2 2023, which included lessons learned from the project.
Peak Shaving Pilot Project	RG&E installed a 2.2MW / 8.8 MWh battery storage system at its Substation127 in Farmington in December of 2018. We tested three use cases: substation peak demand reduction, ability to reduce customer power quality issues, and Operations & Maintenance ("O&M") cost reduction. The

Project	Status
	Company filed a white paper in its 2023 rate case highlighting each use case and project lessons learned through mid-2022.
Distribution Circuit Deployed BSS	NYSEG installed a 477 kW / 1,890 kWh energy storage system on an ESC circuit in 2018. We tested three use cases: daily circuit peak reduction and load shaping, our ability to maintain circuit loading within the hypothetical rating, and voltage regulation. The Company filed a white paper in its 2023 rate case highlighting each use case and project lessons learned through mid-2022.
Utility-Owned Projects	
Stephentown Substation BESS	Proposed utility-owned 1.31 MW / 2.21 MWh ESS located at NYSEG's Stephentown substation that will reduce substation transformer overload for up to 10 years. The substation's current summer peak load is 97%. The project was approved in NYSEG's 2023 Joint Proposal. NYSEG is currently analyzing several RFP bids received for the project and expects to issue a PO to the winning bidder in early Q3 2025. The tentative in-service date for the project is on or before Q3 2026.
Wales Center Substation ESS	Proposed utility-owned 1.0 MW / 4.34 MWh ESS located at the Wales Center substation in NYSEG's service territory, with an average summer peak load of 92% and 2.38 MW of intermittent DERs interconnected and an additional 5.0MW of DERs in the interconnection queue. The project will reduce transformer overload and increase DER hosting capacity. The project was approved in NYSEG's 2023 Joint Proposal. NYSEG is currently analyzing several RFP bids received for the project and expects to issue a PO to the winning bidder in early Q3 2025. The tentative in-service date for the project is on or before Q3 2026.

<u>Future Implementation and Planning</u>: Describe the future implementation that is planned to be deployed by June 30, 2030, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2030 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation; Described where and how plans for topic-related work and investments affect the CGPP; Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

We continue to follow our four-step integration and deployment process in planning and implementing energy storage projects. The four stages of the process are:

1. Learn
2. Build
3. Integrate into Planning, Grid Operations, Interconnections, and Information Sharing
4. Deploy

This process ensures continuous improvement as the Companies plan future energy storage deployments across the NYSEG and RG&E service territories. Below is a listing of planned energy storage initiatives which require additional work and investment to support the future implementation.

<u>Utility-owned Storage Projects:</u> NYSEG continues to advance the Stephentown and Wales Center energy storage projects, which will provide peak shaving and increased hosting capacity to both substations. We plan to issue a purchase order for these projects in early Q3 2025, and both projects are expected to be in service on or before Q3 2026. Both NYSEG and RG&E continue to evaluate future energy storage projects as part of its integrated system planning activities, and plan to propose future projects to solve system needs related to reliability, resiliency, and load growth due to electrification.

<u>Portable Storage Applications:</u> The Companies are in the early stages of identifying portable energy storage applications to address capacity needs related to electrification.

There is significant load growth expected from the electrification of transportation and heating, but there is also uncertainty in the timing, location, and magnitude of the expected growth. We believe portable ESS can help address system needs that arise from electrification while traditional infrastructure is deployed. Once the new infrastructure is in place, the portable storage system could be redeployed to a new location with emerging system needs.

<u>Bulk Storage UDR Solicitation:</u> NYSEG and RG&E are each targeting a minimum of 10 MW of bulk storage awarded within their respective service territories, assuming that projects are financially viable and deliver sufficient value to customers. Awarded contracts (if any) are expected to be complete by Q3 2026, with the awarded storage projects in service by December 31, 2030. The Companies recently released a fourth RFP on June 9, 2025 with expected responses due August 4, 2025

<u>NWA Projects:</u> The Companies continue to evaluate all capital projects for NWA solutions. Four projects are expected to have RFPs released for them between 2025 – 2027. These projects are Java Peak Shaving, Java Microgrid, Ferndale Substation, and Holland Substation. The solutions for these projects could be third party owned ESS or other approved solutions.

Stakeholder Needs

The Companies' work on energy storage initiatives is expected to support stakeholder needs by 2030 and beyond. Storage developers will have the opportunity to submit bids in the upcoming UDR bulk storage solicitation for projects expected to be in service by 2030. The expected contract term is up to15 years for these projects, assuming financially viable projects are awarded contracts. As a result, these projects are expected to remain in service through the mid-2040s.

An additional storage opportunity for developers is NWA solicitations. Although NWA solicitations are technology-agnostic, energy storage is expected to be a competitive solution for these projects. The Companies screen all capital projects to see if they are suitable for a NWA solicitation, presenting future opportunities for 3rd party ownership of energy storage by developers.

The energy storage interconnection process remains a focus for the Companies. As noted in the Current Progress section, the Companies continue to work with the IPWG and the ITWG to propose amendments to Appendix K and the NYSSIR. These process improvements are expected to support energy storage development through 2030 and beyond.

Additionally, utility owned storage systems will bring benefits to customers by increasing the reliability and resiliency of our system. For example, the Stephentown and Wales Center energy storage projects will provide peak shaving services to overloaded transformers and defer the replacement cost of the transformer. NYSEG and RG&E also continue to evaluate future energy storage projects that increase the reliability and resiliency of our system for the benefit of all customers.

Lastly, each of the Companies' energy storage initiatives helps to advance the New York state goal to deploy 6,000 MW of storage in support of the CLCPA objectives. Through the programs and projects mentioned above, NYSEG and RG&E are supporting additional deployment of storage projects across the state.

Interaction with CGPP

The Companies' energy storage initiatives also feed into the CGPP. The Companies, along with the other Joint Utilities members, have supported the ATWG in preparing an Advanced Technology Screening Analysis. The analysis is intended to assist planners in considering advanced technologies as potential solutions to grid needs identified as part of the CGPP. One of the advanced technologies considered in the analysis is energy storage for T&D applications. The Companies provided input on energy storage cost assumptions for the analysis. In addition, the Joint Utilities' Energy Storage study provides applications for non-market T&D services, including flexible transmission capacity and large-scale renewable enablement, which are applicable to the CGPP. The Companies will continue to work with the other Joint Utilities members and the broader ATWG on drafting the energy storage section of the Advanced Technology Screening Analysis.

In addition, the Joint Utilities' CGPP work included publishing the CGPP Stage 1 Results at the August 2024 Technical Conference [47] including energy storage resource needs through 2042 for modeled scenarios. The CGPP scenarios included a "Low-Transmission Impact" scenario with lower storage costs modeled for Zones A-F. [48] The modeled scenarios in the CGPP Stage 1 Results show substantial energy storage investments will be required across New York State, with the 2042 resource need for statewide energy storage ranging from 16.5 GW to 42.1 GW.

EXHIBIT 2.4-2: ENERGY STORAGE ROADMAP

Goal	Achievements (2023-2025)	Short-Term Initiatives (2026-2027)	Long-Term Initiatives (2028-2030)
NWA Projects including ESS	• Completed execution of Stillwater NWA ESS	• NWA RFPs: Java Microgrid, Java Peak Shaving, Holland Substation, Ferndale Substation (may include ESS or other approved technologies) • Continue to administer Stillwater contract and perform measurement and verification. • Additional NWA projects that incorporate storage	• Identify additional NWA projects that may incorporate storage • Administer and monitor any new NWA Storage Projects • Continue to administer Stillwater ESS • Implement Java Microgrid, Java Peak Shaving, Holland Substation, and Ferndale Substation projects (may include ESS or other

[47] Case 20-E-0197, Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, Joint Utilities of New York, CGPP: Description of Process, Stage 1 Results; August 2024 Technical Conference; filed 08/28/2024; https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={10629A91-0000-C11E-9E71-8BB930A57BD4}

[48] Case 20-E-0197, Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, NYISO Coordinated Grid Planning Process (CGPP): Summary of Stage 1 Capacity Expansion Analysis Results; CGPP Technical Conference; August 22, 2024; filed 08/28/2024; https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={10629A91-0000-CF3D-9A14-9D7932BC47C0}

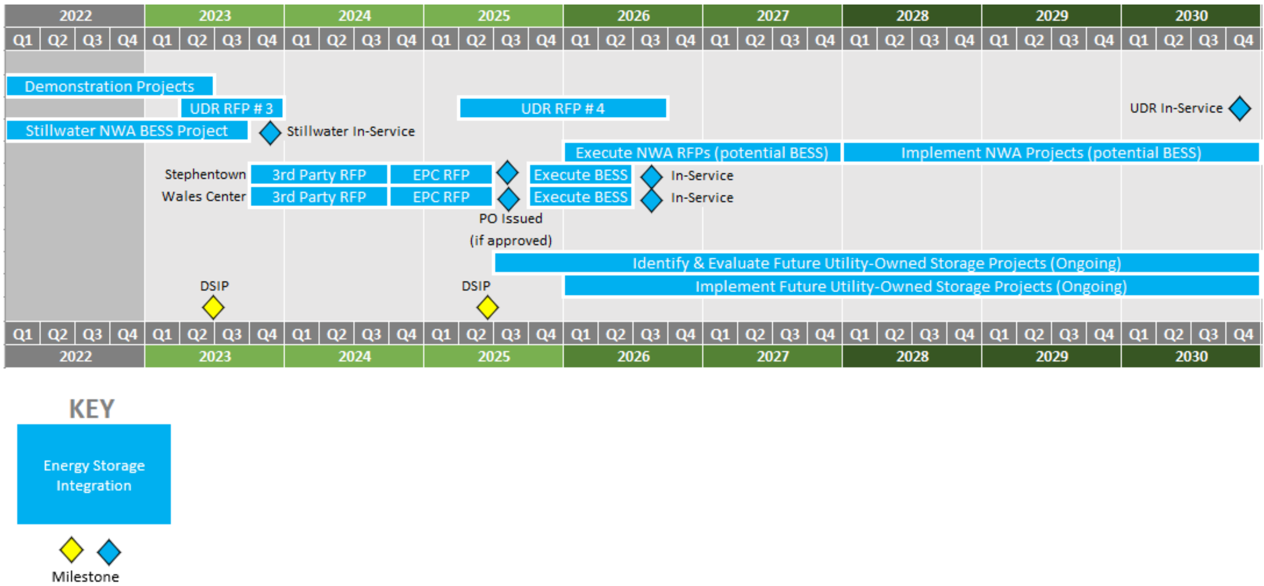
Goal	Achievements (2023-2025)	Short-Term Initiatives (2026-2027)	Long-Term Initiatives (2028-2030)
			approved technologies)
Propose Utility Ownership of Storage ("UOS")	• Incorporated Stephentown and Wales Center energy storage projects into 2023 rate case and joint approval • Completed RFP for third party developer-owned model for Stephentown and Wales Center energy storage projects • Initiated RFP for utility-owned model for Stephentown and Wales Center energy storage projects	• Execute Stephentown and Wales Center utility-owned storage projects (if approved) • Propose mobile storage projects as part of proactive planning proceeding • Identify opportunities for CLCPA-related storage, including utility ownership of storage • Identify and propose non-market UOS projects for reliability and resiliency	• Identify opportunities for CLCPA-related storage, including utility ownership of storage • Propose additional non-market UOS projects
Develop Utility Dispatch Rights Bulk Storage Solution	• Completed 3rd round of UDR bulk storage RFPs • Initiate 4th round of RFPs	• Execute UDR bulk storage projects (if awarded)	• Execute UDR bulk storage projects (if awarded)
Develop and integrate storage into utility planning and operations	• Completed and filed Joint Utilities' (JU) Study of Non-Market T&D Energy Storage Use Cases and Related Process Proposals • Added resources to energy storage team in line with Companies' latest	• Refine and improve energy storage market forecasting • Refine existing and develop improved beneficial storage locational tools • Execute on refined monitoring and control strategy	• Refine and improve energy storage market forecasting • Refine existing and develop improved beneficial storage locational tools • Execute on refined monitoring and control strategy

Goal	Achievements (2023-2025)	Short-Term Initiatives (2026-2027)	Long-Term Initiatives (2028-2030)
	approved rate proceeding	• Increase internal storage competencies	• Increase internal storage competencies
Develop and Complete Demonstration Projects	• Completed and filed closeout reports for energy storage REV demonstration projects including the Integrated EV Charging & Battery Storage and Aggregated BTM Battery Storage projects	• Assess additional innovation projects innovative emerging technology energy storage pilots and projects • Implement and scale beneficial technologies	• Assess additional innovative emerging technology energy storage pilots and projects • Implement and scale beneficial technologies

Integrated Implementation Timeline: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2030. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

See below for the Integrated Implementation Timeline for the Companies' Energy Storage Integration initiatives.

EXHIBIT 2.4-3: ENERGY STORAGE TIMELINE



Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E have identified four risks that relate to the deployment of energy storage, and have taken measures to mitigate each risk, as shown in Exhibit 2.4-4

EXHIBIT 2.4-4: ENERGY STORAGE RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
Project Cost Overruns & Schedule Risk: Uncertainties in energy storage costs and development processes can lead to project delays / additional costs.	• The Companies have assigned internal resources to track energy storage project costs and schedule, and are pursuing an Engineering, Procurement, and Construction (EPC) model for smaller deployments where a third-party vendor is responsible for much of the energy storage project scope which mitigates the risk of project cost overruns.
Market Revenues: Energy storage projects that receive revenues from the NYISO are subject to market volatility.	• The Companies can enter into forward contracts / hedges to reduce the variability of future revenues.
Energy Storage Project Performance: Projects are developed to meet a future system need and must meet performance specifications to solve the need	• NYSEG and RG&E are developing energy storage projects that include commercial availability, and performance guarantees to reduce the risk of non-performance.
Energy Storage Fire Safety Risk: Lithium-ion battery energy storage systems have unique fire safety risks not present in other technologies.	• The Companies have updated their energy storage standard to require industry standard fire protection (e.g. NFPA 855, UL 9540) and will follow the recommendations of the New York Inter-Agency Fire Safety Working Group for future energy storage deployments.
Community Opposition: Community leaders and members oppose the siting and permitting of energy storage in their community	• The Companies regularly engage community members both to spread information on safely operating energy storage and to provide information for specific projects early in the development lifecycle.
Internal Resources & Organizational Alignment: Lack of company resources and/or organizational misalignment may prevent energy storage projects from moving forward.	• The Companies have added resources in line with the 2023 approved Joint Proposal that are dedicated to energy storage. The team works internally to ensure alignment across all stakeholders when developing energy storage projects.

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category's needs will be met over time; Describe and explain the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

Energy Storage Stakeholder Goals & Needs

There are multiple stakeholders with an interest in the Companies' energy storage initiatives. These stakeholders include customers with and without BTM energy storage, storage and DER developers, energy storage manufacturers and integrators, and research firms, as well as NY state entities such as DPS, NYSERDA, and the various NY electric utilities.

Many of the goals of these stakeholders overlap, especially with regards to interconnection processes and tariffs applicable to storage projects. Specifically, energy storage/DER developers and customers with BTM storage both have a need for an efficient interconnection application and study process. The Companies continue to improve their energy storage interconnection process as described in the Current Progress and Future Implementation sections above. Stakeholder engagement on the process continues to take place through the IPWG and the ITWG. Further information regarding DER Interconnections can be found in the DER Interconnections section of the DSIP.

Customers without BTM storage mainly have goals related to reliability and cost. The Companies work to ensure that all energy storage initiatives deliver reliability and resiliency benefits to customers while also ensuring the storage solution is cost-effective compared to a traditional solution.

Both customers with BTM energy storage and storage/DER developers have financial goals related to storage deployments, which often take the form of energy bill reductions, revenue generation, or both. NYSEG and RG&E support these goals through tariffs related to demand charges and standby service for cost reductions, and through tariffs related to VDER and buyback service for revenue generation. Additional information about how Company tariffs support stakeholder goals can be found in the Current Progress section.

Storage developers have goals around storage project development and construction that support their firms' broader growth goals. NYSEG and RG&E offer multiple avenues to collaborate on storage project development throughout their service territories. The Stephentown and Wales Center utility-owned storage ESS projects presented an opportunity for developers to bid into multiple RFPs. In addition, developers have opportunities to bid their projects into the Companies' UDR bulk storage solicitations, as well as any future NWA projects where an ESS solution may fulfill a grid need. More information about the timing of these opportunities is shown in the Integrated Implementation Timeline section.

Utility Needs from Stakeholders

The Companies' energy storage initiatives also benefit from interacting with various stakeholders, especially with regards to information and capabilities provided by third parties with ESS expertise. On ESS safety, the Companies work with a variety of stakeholders to inform ESS safety standards, including EPRI, NYSERDA, and ESS integrators and developers. NYSERDA specifically provides information to the Joint Utilities related to the recommendations of the New York Inter-Agency Fire Safety Working Group. In addition, ESS integrators and developers provide the Companies with technical and commercial information on system performance and costs, which supports the evaluation of storage projects that fulfill a system need.

NYSEG and RG&E also have information needs for storage systems interconnecting to the distribution system. As noted in the Current Progress section, DER developers or customers looking to interconnect energy storage must provide the information requested in Appendix K of the NYSSIR. This requires the interconnecting party to provide technical information related to the storage design, system operating characteristics, and information related to market participation and compensation under the applicable tariff. This information assists the Companies maintain an efficient and effective interconnection process for ESS

Stakeholder Engagement – Opportunities, Tools, and Available Information

NYSEG and RG&E engage stakeholders through multiple channels to solicit energy storage services and information. The Companies invite storage developers and EPC firms to participate in energy storage RFPs of various types, including utility-owned storage projects, third-party bulk storage solicitations (also known as Utility Dispatch Rights), and NWA projects with battery storage as an available technology option. Information regarding these opportunities is communicated via email, posted on company websites, and filed in the applicable proceeding on the NY DPS Document and Matter Management system (DMM). This helps to ensure the implemented storage solutions meet the needs of both the Companies and storage developers. In addition, the Companies meet regularly with energy storage developers, ESS integrators, research firms, and other energy storage related businesses to keep abreast of industry advancements, challenges, and lessons learned. This supports the Companies' energy storage initiatives by utilizing the latest information, resulting in robust projects that provide additional value to customers.

NYSEG and RG&E also provide information and tools to energy storage stakeholders. Information about hosting capacity is provided on the Companies' hosting capacity maps, as detailed in Current Progress section. Energy storage interconnection applications are managed through the Companies' online portal, which includes a wealth of interconnection information including Appendix K for storage interconnections. Lastly, information regarding the NYSEG and RG&E tariffs can be found on Company websites, including summary information and the tariffs themselves. These tools and information support customers and DER developers interested in installing storage to ensure it meets both their needs and the needs of the Companies.

Additional Detail

As outlined in the recently issued "New York's 6 GW Energy Storage Roadmap Policy Options for Continued Growth in Energy Storage" significant energy storage integration will be needed within the five-year planning horizon of the DSIP Update filing.[9] Meanwhile, evolving initiatives for achieving New York State's energy storage goals will likely require *corresponding adjustments to utility deployment plans, use cases, and forecasts. Areas of particular interest to DPS Staff related to energy storage include:*

- *existing energy storage resources in the distribution system;*
- *the utility's planned energy storage projects;*
- *a five-year energy storage deployment by the utility and/or third-parties;*
- *potential energy storage locations and applications that could benefit customers and/or the electric system;*
- *resources and functions needed for integrating energy storage with utility grid operations;*
- *resources and functions needed for integrating energy storage with utility billing and compensation functions; and*
- *the utility's alignment with New York State's energy storage goals and initiatives.*

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following details for the areas of interest listed above, especially the means and methods to plan for energy storage deployment in the distribution system:

1) Provide the locations, types, capacities (power and energy), configurations (i.e. standalone or co-located with load and/or generation), and functions of existing energy storage resources in the distribution system.

See Exhibit 2.4-1 above for a summary of the configurations and functions of our current energy storage resources that are either company owned or company contracted (e.g. NWA projects). The following ESS projects are currently in service:

- Stillwater Storage NWA Project: 1MW / 2.9 MWh ESS;
- Aggregated BTM Energy Storage: 765 kW / 3,080 kWh total ESS capacity at six sites;
- Integrated EV Charging and Battery Storage System: 150 kW / 600 kWh ESS
- Peak Shaving Pilot Project: 2.2MW / 8.8 MWh ESS; and
- Distribution Circuit Deployed BSS: 477 kW / 1,890 kWh ESS.

Data on all energy storage interconnected to NYSEG and RG&E's distribution system can be found on the NY DPS website, which is labeled "NYSEG and RG&E Interconnection Queue Data" under the "SIR Inventory Information" heading. [15] In addition, there are three 20 MW energy storage resources in NYSEG's service territorites that have interconnected through the NYISO interconnection process. Two resources are 20 MW lithium-ion ESS projects and one is a 20 MW flywheel energy storage project. The flywheel project is excluded from the energy storage project totals presented. Summary tables displaying the count of energy storage projects interconnected to NYSEG and RG&E's system as of February 27, 2025 are below. The summary tables provide information on project configurations (i.e. standalone storage or storage + solar), energy storage power capacities, and locations in the form of NYISO zone. No breakout for energy storaage technology is available, but the Companies believe that a large majority of the storage projects are lithium-ion ESS with the exception of the flywheel project mentioned earlier.

Energy Storage Projects Interconnected to NYSEG System by Capacity
As of February 27, 2025 – Data source: SIR Inventory Information [49] & NYISO 2024 NYCA Generators Listing

EXHIBIT 2.4-5: ENERGY STORAGE PROJECTS INTERCONNECTED TO NYSEG SYSTEM BY CAPACITY

Energy Storage Capacity	# Solar + Storage Projects	# Standalone Storage Projects	Total Storage Projects
< 10 kW	274	26	300
10-25 kW	270	35	305
25-50 kW	11	2	13
50-100 kW	4	3	7
100-1000 kW	1	5	6
1.0-5.0 MW	5	1	6
5.0-25.0 MW	1	2	3
All Capacities	**566**	**74**	**640**

Energy Storage Projects Interconnected to RG&E System by Capacity
As of February 27, 2025 – Data source: SIR Inventory Information

[49] NYSEG and RG&E Interconnection Data, SIR Inventory Information, Distributed Generation Information, NY DPS Website, https://dps.ny.gov/nyseg-and-rge-interconnection-queue-data

EXHIBIT 2.4-6: ENERGY STORAGE PROJECTS INTERCONNECTED TO RG&E SYSTEM BY CAPACITY

Energy Storage Capacity	# Solar + Storage Projects	# Standalone Storage Projects	Total Storage Projects
< 10 kW	41	9	50
10-25 kW	36	4	40
25-50 kW	1	0	1
50-100 kW	0	0	0
100-1000 kW	2	0	2
1.0-5.0 MW	1	1	2
5.0-25.0 MW	0	0	0
All Capacities	**81**	**14**	**95**

Energy Storage Projects Interconnected to NYSEG System by NYISO Zone
As of February 27, 2025 – Data source: SIR Inventory Information & NYISO 2024 NYCA Generators Listing

EXHIBIT 2.4-7: ENERGY STORAGE PROJECTS INTERCONNECTED TO NYSEG SYSTEM BY NYISO ZONE

NYISO Zone	# Solar + Storage Projects	# Standalone Storage Projects	Total Storage Projects
H	173	17	190
E	136	12	148
C	122	22	144
F	75	13	88
G	27	2	29
A	21	8	29
D	12	0	12
All NYISO Zones	**566**	**74**	**640**

Energy Storage Projects Interconnected to RG&E System by NYISO Zone
As of February 27, 2025 – Data source: SIR Inventory Information

EXHIBIT 2.4-8: ENERGY STORAGE PROJECTS INTERCONNECTED TO RG&E SYSTEM BY NYISO ZONE

NYISO Zone	# Solar + Storage Projects	# Standalone Storage Projects	Total Storage Projects
B	81	14	95

2) *Describe the utility's current efforts to plan, implement, and operate beneficial energy storage applications. Information provided should include:*

   a. *a detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long range energy storage plans;*

   b. *the original project schedule;*

   c. *the current project status;*

   d. *lessons learned to-date;*

   e. *project adjustments and improvement opportunities identified to-date; and,*

   f. *next steps with clear timelines and deliverables.*

See Current Progress and Future Implementation and Planning sections above for a complete listing of the Companies' energy storage projects. Additional information about the Utility-Owned ESS projects is given below.

Stephentown Substation ESS

The Stephentown ESS project is a planned 1.31 MW / 2.21 MWh ESS located at NYSEG's Stephentown substation that will provide peak-shaving services for the overloaded 34.5 kV / 4.8 kV transformer bank #1. This project will defer the cost of upgrading the transformer bank, providing benefits to customers.

Wales Center Substation ESS

The Wales Center ESS project is a planned 1.0 MW / 4.34 MWh ESS located at NYSEG's Wales Center substation that will provide peak-shaving services for the overloaded 34.5 kV / 4.8 kV transformer bank #1. The project will also support integration of additional DER by charging during times of excess solar generation. This project will defer the cost of upgrading the transformer bank, providing benefits to customers.

Project Schedule & Current Project Status

As outlined in Appendix N of the Companies' 2023 Joint Proposal[50], the Companies were initially required to issue RFPs within 6 months of a final Commission order. On March 28, 2024, NYSEG requested an extension to the RFP date. On April 11, 2024, the PSC Secretary granted an extension on the RFPs until September 3, 2024.

RFPs have been initiated for both projects, including a set of RFPs for a third-party ownership model and a set of RFPs where the projects would be owned by NYSEG, consistent with Appendix N of the Joint Proposal adopted by the Commission in the 2023 Rate Order. A third-party RFP was conducted between September 3, 2024 and November 19, 2024 to solicit proposals from developers to build, own, and operate the Stephentown and Wales Center energy storage projects. During the course of the RFP, 11 different vendors expressed interest in submitting a bid for the project, either through attending the pre-bid conference or requesting to be added to the RFP email distribution list. Despite interest from multiple potential bidders, no vendors submitted proposals to develop and operate these projects during the RFP process. As a result, the Companies, working with DPS Staff, have determined that both projects will be owned by NYSEG.

Project Next Steps

The Companies are currently analyzing several RFP bids received for EPC services for these two projects. Once that analysis is complete, the Companies expect to confirm the projects are still viable and issue a purchase order to the winning bidder in early Q3 2025. The tentative in-service date for both projects is on or before Q3 2026.

Lessons Learned & Improvement Opportunities

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[50] Case 22-E-0317 et al, Order Adopting Joint Proposal, Joint Proposal Attachment 1, Appendix N: Battery Storage RFP Process, filed October 12, 2023.

Although these projects are still in the development process, the Companies have collected a few initial lessons learned through the projects. The third-party RFP indicated that smaller storage projects (e.g. 1 MW and smaller) may not garner as much developer interest. In addition, the Companies are working to streamline and simplify the RFP process to allow for additional vendors to take part in future solicitations.

3) *Provide a five-year forecast of energy storage assets deployed and operated by third-parties. Where possible, include the likely locations, types, capacities, configurations, and functions of those assets.*

Different methods can be used to create a five-year forecast of energy storage deployed by third-parties. One approach utilizes historical growth rates for energy storage deployed in the Companies' service territories. During 2022-2024, the energy storage annual growth rate averaged 3.35% across the NYSEG and RG&E service territories. Applying this growth rate to the currently installed energy storage base results in new storage deployments of 2.4-2.7 MW/year for NYSEG and 0.26-0.29 MW/year for RG&E. A summary table of the resulting five-year forecast of energy storage deployments is given below.

EXHIBIT 2.4-9: FIVE-YEAR ENERGY STORAGE FORECAST: HISTORICAL GROWTH APPROACH

Year	NYSEG – Cumulative Energy Storage Deployed (MW)	RG&E – Cumulative Energy Storage Deployed (MW)
2025	71.3	7.7
2026	73.7	8.0
2027	76.2	8.2
2028	78.7	8.5
2029	81.4	8.8
2030	84.1	9.1

A second approach for creating a five-year forecast of energy storage is to utilize the interconnection queues for NYSEG and RG&E to estimate future storage deployments. As of 2/27/2025, the energy storage capacity in the interconnection queue is 357.7 MW for NYSEG and 61.5 MW for RG&E. An April 2024 study from Lawrence Berkeley National Laboratory[51] estimated that only 9% of capacity in the NYISO interconnection queue

[51] Lawrence Berkeley National Laboratory (NYSEG); Queued Up: 2024 Edition; Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 dated April 2024 at p. 29; https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf

reaches its Commercial Operations Date (COD). Applying this 9% assumption to the the energy storage capacity in NYSEG and RG&E's queue results in 32.2 MW reaching COD for NYSEG and 5.5 MW reaching COD for RG&E. Assuming this storage capacity is installed in equal increments through the end of 2030, the annual new storage deployments would be 5.7 MW/year for NYSEG and 1.0 MW/year for RG&E. A summary table of the resulting five-year forecast of energy storage deployments is given below.

EXHIBIT 2.4-10: FIVE-YEAR ENERGY STORAGE FORECAST: INTERCONNECTION QUEUE APPROACH

Year	NYSEG – Cumulative Energy Storage Deployed (MW)	RG&E – Cumulative Energy Storage Deployed (MW)
2025	74.1	8.3
2026	79.7	9.3
2027	85.4	10.3
2028	91.0	11.2
2029	96.7	12.2
2030	102.3	13.2

The historical growth approach results in a growth of 12.8 MW (17.9%) for NYSEG and 1.4 MW (17.9%) for RG&E over a five year time horizon. The interconnection queue approach results in a growth of 28.3 MW (38.2%) for NYSEG and 4.9 MW (58.5%) for RG&E over a five year time horizon.

There are multiple policy and economic factors that may impact energy storage deployment. Factors that may result inan increase in storage deployments include the implementation of NYSERDA's Bulk Energy Storage Program including the Index Storage Credit Mechanism [52]as well as expected continued declines in the installed cost of ESS[53]. Conversely, factors that may result in a decrease in storage deployments include uncertainties around the federal Investment Tax Credit (ITC) as well as current and future tariffs and countervailing duties, which may drive up the costs of both battery cells and containerized ESS units. These postive and negative factors increase the uncertainty

[52] Case 18-E-0130 In the Matter of Energy Storage Deployment Program; NYSERDA Bulk Energy Storage Implementation Plan Proposal filed October 18, 2024. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F099A092-0000-C938-98D5-9D3FB839557F}

[53] Case 18-E-0130 In the Matter of Energy Storage Deployment Program; NY DPS, State of Storage in New York, Annual Energy Storage Deployment Report Pursuant to Public Service Law §74, filed 4/15/2025; at p. 7. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F03F3A96-0000-CE19-A1B9-03455BB61011}

surrounding a five-year energy storage deployment forecast.

4) *Identify, describe, and prioritize the current and future opportunities for beneficial use of energy storage located in the distribution system. Uses considered should encompass functions which benefit utility customers, the distribution system, and/or the bulk power system. Each opportunity identified should be characterized by:*

   a. *location;*

   b. *the energy storage capacity (power and energy);*

   c. *the function(s) performed;*

   d. *the period(s) of time when the function(s) would be performed; and,*

   e. *the nature and economic value of each benefit derived from the energy storage resource.*

Current opportunities include the Stephentown and Wales Center ESS projects detailed in the Current Progress section with additional information on location and storage capacity provided in question 2 above. Both projects would provide peak-shaving services for the overloaded transformer bank by discharging during times of peak-load in both the summer and winter. The Wales Center ESS would also provide DER integration support by charging during times of light load and high solar generation. These projects realize positive economic value by deferring the upgrade cost associated with replacing the transformers.

Future opportunities for beneficial energy storage deployments include portable energy storage, as detailed in the Future Implementation and Planning section. Although the locations and capacities of these deployments are not yet known, these projects provide additional flexibility by serving system needs arising from electrification of transportation and heating. This would provide additional time for traditional infrastructure to be deployed while still meeting system needs, which provides economic value for customers.

5) *Identify and describe all significant resources and functions that the utility and stakeholders use for planning, implementing, monitoring, and managing energy storage at multiple levels in the distribution system.*

   a. *Explain how each of those resources and functions supports the utility's* *needs.*

b. *Explain how each of those resources and functions supports the stakeholders' needs.*

As shown in Exhibit 2.4-11, energy storage projects touch many business areas within the Companies, with a listing of each function's contribution to energy storage projects. These resources support stakeholders' needs in planning, implementing, monitoring, and managing energy storage. Specifically, the Interconnections team works to ensure an efficient interconnection application process for DER developers. The Rates team creates and maintains tariffs that support the financial goals of DER developers and customers with BTM storage through the VDER, standby, and buyback tariffs. The Clean Energy Policy and Planning teams work on storage solicitations, including NWA and bulk storage solicitations, which supports project development opportunities for storage developers. All teams work collectively to ensure energy storage initiatives deliver reliability and resiliency benefits to all customers in a cost-effective manner. See the Stakeholder Engagement section for additional details on stakeholder needs, utility needs from stakeholders, and available information for stakeholders.

EXHIBIT 2.4-11: FUNCTIONS AND RESPONSIBILITIES CONTRIBUTING TO ESS PROJECTS

Function	Responsibilities
Clean Energy Policy	Collaboration on clean energy policy projects and pilots, including energy storage projects.
Integrated Planning	Integration of ESS projects and pilots with the grid, assessment of stacked benefits, and NWA procurement activities.
Project Management	Oversight and management of identified and approved ESS projects and pilots.
Distribution Design/Planning	Identification of ESS beneficial locations including power flow modeling to determine how the project location impacts the local distribution configuration and to support interconnection.
Transmission Planning	Identification of ESS beneficial locations and assessment of potential impacts on the transmission network.
Customer Interface	Interactive relationships with storage developers and end-use customers.
Metering	Design and implement metering scheme(s) supporting ESS projects and pilots.
Safety	Ensure any ES project or pilot implementation meets all safety requirements.
Market Operations	Responsible for realizing value in NYISO markets for ESS projects where applicable and implements scheduling for any projects awarded Utility Dispatch Rights contracts.
IT/OT and other Communications	Integration with NYSEG/RG&E grid operations systems.
Distribution Operations	Substation and distribution asset management including ESS projects and pilots.
Engineering	Distribution and substation engineering, protection schemes, and integration of ESS with the Energy Control System.
Technical Services	Quality Management, Environmental, and Cost Control support.
Interconnections	Ensure timely, safe, and reliable interconnection of ESS projects.
Rates	Testing of innovative rate designs that enable DER deployment.

6) *Describe the means and methods for determining the real-time status, behavior, and effect of energy storage resources currently deployed in the distribution system. Information produced by those means and methods should include:*

   a. *the amount of energy currently stored (state of charge);*

   b. *the time, size, duration, energy source (grid and/or local generation), and purpose for each charging event;*

   c. *the time, size, duration, energy source (grid and/or local generation), and purpose of each energy storage discharge;*

   d. *the net effect (amount and duration of supply or demand) on the distribution system of each charge/discharge event (considering any co-located load and/or generation); and*

   e. *the capacity of the distribution system to deliver or receive power at a given location and time.*

As detailed in section 2.3 Grid Operations, the Companies are working towards the implementation of a DERMS that facilitates visibility and control of all DERs connected to the distribution system, including energy storage resources. The DERMS will enable awareness and control of DERs in the system, including the DER's grid connection, potential grid contributions, control capabilities, and market or program constraints.

For energy storage resources, the DERMS system is expected to include interval data on state of charge, real and reactive power for charge and discharge events, and load at the point of interconnection. This will allow for storage resources to be scheduled and dispatched (i.e. charged and discharged) to meet system needs.

The current battery storage demonstration projects shown in Exhibit 2.4-1 are currently managed through third-party software. The Companies rely on this software to retrieve real-time and historical battery storage performance, including data on the battery state of charge, charging/discharging energy flows, reactive power, and load at the site.

7) *Describe the means and methods for forecasting the status, behavior, and effect of energy storage resources in the distribution system at future times. Forecasts produced by the utility should include:*

   a. *the amount of energy stored (state of charge);*

   b. *the time, size, duration, energy source (grid and/or local generation), and purpose of charging events;*

   c. *the time, size, duration, consumer (grid and/or local load), and purpose of energy storage discharges; and,*

   d. *the net effect on the distribution system of each charge/discharge event (considering any co-located load and/or generation); and,*

   e. *the capacity of the distribution system to deliver or receive power at a given location and time.*

As discussed in section 2.2 Advanced Forecasting of the DSIP, the Companies are currently working to build foundational forecasting processes that will support different types of DERs, including energy storage resources. The data foundation will include the type, location, and other attributes of DERs such as storage capacity. In addition, the Companies are working to launch the advanced load forecasting pilot project that will generate time-series forecast for every distribution feeder including the impacts of DERs including energy storage. This is turn will support the planning and evaluation of future storage projects, both for NWA projects and utility-owned storage projects.

NYSEG and RG&E continue to deploy and integrate AMI meters into our systems. This will allow the Companies to analyze the forecast accuracy for all types of DERs including energy storage, as well as the impact of DERs such as storage on substation-level forecasts.

The Companies have also worked to make use of EPRI's DER-VET tool[54]to simulate energy storage project behavior and forecast market revenue. The DER-VER tool can be used for operational forecasting of energy storage projects that optimizes value, including time-series modeling of state of charge, charging events, discharging events, and interaction with load and solar generation on the distribution circuit. The Companies have used the tool to estimate how energy storage resources can be used

[54] EPRI Distributed Energy Resource Value Estimation Tool (DER-VET); https://www.der-vet.com/

to increase DER hosting capacity. In addition, DER-VET allows the Companies to forecast revenues and costs over a 15-year contract duration for proposed UDR projects. This supports the ongoing evaluation of bulk storage solicitations to enable both NYSEG and RG&E to procure a minimum of 10 MW each of UDR contracts.

8) *Describe the resources and functions needed to support billing and compensation of energy storage owners/operators.*

As discussed in section 2.10 Billing and Compensation of the DSIP, the Companies have implemented and automated numberous compensation methodologies for DER billing including methodologies supporting energy storage. For on-site storage projects, the Commission expanded the Value Stack compensation methodlogy to standalone storage and energy storage paired with eligible generation. The Companies have worked to automate the VDER billing methodology. Separately, many larger storage projects (> 1 MW capacity) in the Companies' service territory are co-located with Community Distributed Generation (CDG) projects. CDG billing requires multiple internal resources, and the Companies work with the DER providers to provide timely and accurate billing for customers. Additional billing automation work is necessary to support CDG project growth, as the number of VDER CDG projects continues to grow in the Companies' service territory as detailed in section 2.10 Billing and Compensation

9) *Identify the types of customer and system data that are necessary for planning, implementing, and managing energy storage and describe how the utility provides those data to developers and other stakeholders.*

As discussed in the Stakeholder Engagement section of section 2.4 Energy Storage Integration, the Companies make available a wealth of tools and information related to energy storage deployments. This includes the Companies' hosting capacity maps and online portal for interconnection applications. In addition, the Companies' publish information regarding their tariffs and storage project opportunities such as NWA and UDR on Company websites. In addition, stakeholders provide data to the Companies' regarding storage safety standards, interconnection information (e.g. SIR Appendix K), ESS cost and performance data, and bids for NWA and UDR projects. See the Stakeholder Engagement section for additional detail.

10) *By citing specific objectives, means, and methods describe in detail how the utility's accomplishments and plans are aligned with the objectives established in the CLCPA.*

As discussed in previous sections – such as the Current Progress, Future Implementation & Planning, and Stakeholder Engagement sections – the Companies have several initiatives that contribute to New York State's 6 GW energy storage goal, which support the CLCPA objectives to generate 70 percent of the state's electricity from renewable sources by 2030 and 100 percent zero emission electricity by 2040.

Specific initiatives supporting the energy storage build-out in the Companies' service territory include:

- Support for third-party owned storage projects – As discussed in the Stakeholder Engagement section, the Companies have tools and processes to support storage developers such as hosting capacity maps and an interconnection portal.
- UDR bulk storage solicitation – As detailed in the Current Progress section, the Companies are currently developing a fourth-round solicitation to procure 10 MW of UDR for both NYSEG and RG&E.
- NWA Projects – For NWA projects, the Companies currently operate the Stillwater storage project. The Companies will continue to evaluate all capital projects for NWA solutions, including energy storage as a potential technology. The NWA Java Microgrid project will be revaluated in 2027. This Microgrid slated to be owned by the Companies. More information is available in the Current Progress and Future Implementation & Planning sections.
- Utility Owned Storage Projects – The Companies are currently working to develop the Stephentown substation ESS and Wales Center substation ESS projects as detailed in the Current Progress section. Both NYSEG and RG&E will work to evaluate future energy storage projects that meet system resiliency and reliability needs.

Each of these initiatives will help contribute to the State's 6 GW storage goal by adding storage capacity, which supports the objectives of the CLCPA to generate 70% of the state's electricity from renewable sources by 2030.

2.5 Electric Vehicle Integration

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2023 DSIP Update filing.

Introduction

NYSEG and RG&E support its customers' transition to electrification of the transportation sector and recognize the sector as a major contributor to reducing GHG and a transition to a clean economy. In support of our commitment to customers, growing EV market adoption rates and alignment with federal, state and regulatory policies, NYSEG and RG&E have enabled the customer installation of 2,926 L2 plugs and 447 DCFC plugs[55] as of March 15, 2025, through its programs and incentives. Through a multi-state memorandum of understanding, New York has first committed to a target of 850,000 Zero Emissions Vehicles ("ZEV") by 2025 in 2013, and later committed to have 100% zero emission passenger vehicle in state sales by 2035, 100% zero emission school buses in service by 2035, and 100% zero emission medium-and heavy-duty vehicle in state sales by 2045.[56] [57]

The EV market has grown rapidly over the past decade in the US. In 2013 EVs made up less than 1% of new vehicle sales. That increased to about 3% by the end of 2018 and to over 10% by the end of 2023. In the 4th quarter of 2024, electric vehicles accounted for 11% of total vehicle sales in New York State. [58] As of February 2025, there are over 275,000 electric vehicles on the road in New York State. [59] [60]

Given the EV market growth in our service territories and state and regulatory policy climate, the Companies support the development and integration of infrastructure and technology that enables market growth and supports the decarbonization of the economy.

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[55] EV Make-Ready Program data (includes committed and completed plugs) as of March 15, 2025: https://jointutilitiesofny.org/ev/make-ready

[56] "State Zero-Emission Vehicle Programs: Memorandum of Understanding" Dated and effective October 24, 2013, Parties include Governors of California, Connecticut, Maryland, Massachusetts, New York, Oregon, Rhode Island, and Vermont. Memorandum of understanding includes agreement to coordinate and collaborate to promote effective and efficient implementation of ZEV regulations. https://www.nescaum.org/documents/zev-mou-8-governors-signed-20131024.pdf

[57] NY State Assembly Bill A4302 (nysenate.gov)

[58] See: https://www.atlasevhub.com/market-data/ev-market-dashboard/

[59] See: https://www.atlasevhub.com/market-data/state-ev-registration-data/

[60] One limiting factor for EV growth had been the variety of EV models available to consumers. The number of available models has increased rapidly over the past decade with 23 total models available in 2014, 88 in 2018, and 248 in 2024.

As such, NYSEG and RG&E have worked closely with the Joint Utilities in developing EV initiatives that help the State and Commission meet CLCPA and other environmental goals.

NYS Legislative and Regulatory Policies

Electrification of transportation is a major focus for achieving the CLCPA targets. The Commission has addressed EV related issues and opportunities in Case 18-E-0138, Case 22-E-0236, Case 23-E-0070, and Case 24-E-0364. Over the past few years, there have been several Commission and State EV developments.

Below is a summary of state policies and regulatory proceedings that the Companies have supported:

- On April 24, 2018, the Commission issued the Electric Vehicle ("EV") Instituting Order, [61] which emphasized the importance of decarbonizing the transportation sector and directed the Utilities to address the increased deployment of electric vehicle supply equipment ("EVSE").
- On January 13, 2020, following the passing of the CLCPA, Staff issued its Whitepaper Regarding EVSE and Infrastructure Deployment that described an incentive program to assist in covering the costs of Level 2 and DC Fast Charging ("DCFC") stations. [62]
- On July 16, 2020, the Commission issued the Make-Ready Order, outlining a comprehensive strategy to decarbonize the transportation sector through coordinated utility and market developer investments. In response, the Utilities filed Make-Ready Program proposals to expand EV charging infrastructure for mass market customers by providing incentives for developers and site owners. These programs include make-ready EV infrastructure incentives, the Medium- and Heavy-Duty (MHD) EV Pilot, Fleet Advisory Services, and alternatives to the EV Time-of-Use (TOU) rate structures. A plan was filed towards the end of 2020. Following these filings, Staff created the Electric Vehicle Working Group (Joint Utilities' EV Working Group), which includes several subgroups focused on the various initiatives outlined in the Order.

[61] Case 18-E-0138, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure (EV Proceeding), EV Proceeding Instituting Order (Issued April 24, 2018). https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={734AE4E4-D170-41DA-8FB9-91EA359568F9}

[62] Case 18-E-0138, Staff Whitepaper Regarding Electric Vehicle Supply Equipment and Infrastructure Deployment, dated January 13, 2020. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={652C94FC-7669-4578-9B89-70EC65AC9C55}

- The State has also committed to medium-heavy-duty ("MHD") EV goals, as well. In July 2020, New York was a signatory to a Multi-State Memorandum of Understanding (MHD ZEV MOU) which set a mutual goal among signatories to ensure that 100 percent of all new MHD vehicle sales will be ZEV by 2050 with an interim target of 30 percent MHD ZEV sales by 2030. [63]
- In September 2021, the State passed New York State Senate Bill 2758/Assembly Bill 4302 that targets 100 percent of new light-duty vehicle sales to be ZEV by 2035. [64]
- In December 2021, NY passed New York State Senate Bill S2758/Assembly Bill 4302 which amended the NYS environmental conservation law to include a goal that 100 percent of in-state sales of medium- and heavy-duty vehicles be zero-emission by 2045. [65]
- On April 7, 2022, in the budget passed by New York State Legislature and signed by Governor Hochul, the state established a deadline for the transition to zero emission school buses. Specifically, 100% of new school buses purchased by school districts must be ZEV beginning on July 1, 2027, and 100% of school buses in service statewide must be ZEV by 2035. [66]
- On April 21, 2022, the Commission established a Proceeding to Establish Alternatives to Traditional Demand-Based Rate Structure for Commercial EV Charging, 22-E-0236 in response to NY PSL §66-s requiring Commission to issue an Order approving or modifying a proposal to establish one or more alternatives to traditional demand-based rate structures for light-duty, heavy duty and fleet (Commercial) customers that utilize EV charging.[67]
- On September 29, 2022, Governor Hochul announced that NYS would promulgate a regulatory process to adopt California's Advanced Clean Cars II Regulations, which sets goals for ZEV adoption as a share of new vehicle sales starting at 35 percent for model years 2025 and scaling to 100 percent by 2035. Over the longer term, this will

[63] California Air Resources Board. "15 states and the District of Columbia join forces to accelerate bus and truck electrification." July 14, 2020. https://ww2.arb.ca.gov/news/15-states-and-district-columbia-join-forces-accelerate-bus-and-truck-electrification

[64] NY Senate Bill S2758 (signed into law September 8, 2021). https://www.nysenate.gov/legislation/bills/2021/S2758

[65] NY Senate Bill S2758.

[66] Source: https://www.nysenate.gov/legislation/laws/ENV/A58

[67] Case 22-E-0236, Proceeding to Establish Alternatives to Traditional Demand-Based Rate Structures for Commercial Electric Vehicle Charging, Order Establishing Framework for Alternatives to Traditional Demand-Based Rate Structures (issued April 21, 2022) (Alternative EV Rate Order).

help accelerate activity beyond the already ambitious 2025 targets from the 2013 ZEV MOU and require greater investment in EV charging infrastructure.[68]

- On January 19, 2023, NYS DPS issued an Order requiring NYS Utilities to file a Demand Charge Rebate, EV Phase-In Rate and Commercial Managed Charging Program.[69]
- On April 20, 2023, the Commission established the Proceeding on Motion of the Commission to Address Barriers to Medium and Heavy-Duty Electric Vehicle Charging Infrastructure by issuing the Order Instituting Proceeding and Soliciting Comments. Initial comments in the proceeding were filed on June 5, 2023. [70]
- On November 16, 2023, the Commission's Order Approving Midpoint Review Whitepaper's Recommendations with Modifications for the Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure (Case 18-E-0138) was issued.[71] The EV Infrastructure Make-Ready Program's budget was increased, with 35% of the budget earmarked to benefit disadvantaged communities. Charging infrastructure targets and incentives were also revised.
- On November 20, 2023, the Commission issued the Order Implementing Immediate Solutions Programs (Case 22-E-0236), introducing key measures to support the expansion of commercial EV charging infrastructure. This included the establishment of the Demand Charge Rebate Program. [72]
- On August 15, 2024, the Commission established 24-E-0364: Proactive Planning proceeding, focusing on the proactive planning and development of upgraded electric grid infrastructure to support the increasing electrification of both the building and transportation sectors in New York State. This proceeding aims to address the challenges and opportunities associated with the electrification of

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[68] Governor Hochul's announcement on NY State Transition to Clean Transportation (September 29, 2022). https://www.governor.ny.gov/news/governor-hochul-drives-forward-new-yorks-transition-clean-transportation

[69] Case 22-E-0236, Proceeding to Establish Alternatives to Traditional Demand-Based Rate Structures for Commercial Electric Vehicle Charging. Alternative EV Rate Order Establishing Framework for Alternatives to Traditional Demand-Based Rate Structures issued January 19,2023. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B2043A628-EC7D-4064-9F32-662D82598760%7D

[70] Case 23-E-0070, Proceeding on Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure, Order Instituting Proceeding and Soliciting Comments (issued and effective April 20, 2023). https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={40F19F87-0000-CE10-B9FC-579FE87EB823}

[71] Source: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b6057D98B-0000-C912-9B64-A2D769C4790D%7d

[72] Source: https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=22-e-0236&CaseSearch=Search

medium- and heavy-duty electric vehicles and building electrification. Through this proceeding, the PSC directs the utilities to file a proposal for a long-term coordinated planning process that will address increased expected electrification loads. [73]

- On September 20, 2024, the Order Approving Modifications to the Make-Ready Program introduced several important program updates to enhance the state's EV infrastructure initiative. [74]
- On October 17, 2024, the Commission's Order Implementing Electric Vehicle Charging Rates for Commercial Customers introduced significant measures to support the expansion of commercial EV charging infrastructure. This included the approval of EV Phase-In Rates. [75]

Federal Policies

Federal policy has also played an important role in shaping New York's EV sector.

The Infrastructure Investment and Jobs Act (IIJA), passed in 2021, included several programs:

- National Electric Vehicle Infrastructure (NEVI) program aims to build a publicly accessible EV charging network located along designated alternative fuel corridors in the US. The program has funded DCFC charging along interstate highway corridors through cooperation with NYSDOT, NYSERDA, and the utilities.
- Charging and Fueling Infrastructure (CFI) program provides $2.5 billion in competitive grant funding to build out travel corridor and community charging infrastructure. CFI program investments will fund public EV charging infrastructure across the state, including projects for community L2 and DCFC charging and infrastructure buildout at State University of New York sites.
- Clean School Bus Program designates $5 billion of funding over 5 years (2022 – 2026) to replace existing school buses with zero-emission and clean school buses.

The 2022 Inflation Reduction Act (IRA) included initiatives supporting EV adoption (New Clean Vehicle Tax Credit, Used Clean Vehicle Tax Credit, Commercial Clean Vehicle Tax Credit, and more).

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[73] Source: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={80465791-0000-C51E-B4A0-7B56E347E0F5}

[74] See: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A0841092-0000-CA14-BE46-00FF904783C9}

[75] See https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={D09E9B92-0000-CF15-A640-35C2D49F135B}

Initiatives and Programs

We have a portfolio of 13 initiatives / programs that have been proposed, are in development, or in implementation. See below for a summary.

EXHIBIT 2.5-1: PORTFOLIO

Initiative / Program	Category	Status	Start Date	End Date	Description
L2/ DCFC Make-Ready Program	Supporting Adoption	Implementation	2021	2026	Customer incentives toward electrical make-ready cost of installing and interconnecting new charging infrastructure
Fleet Assessment Service	Supporting Adoption	Implementation	2021	2026	Customer training that supports customers with a fleet assessment and report. Report identifies vehicle options, cost, feasibility, electric rate impact, and electric infrastructure needs for fleet EV adoption
Demand Charge Rebate	Supporting Adoption	Implementation	2024	2025 (proposed)	Rebate for up to 50% of demand charge only available until the start of the EV Phase-in-Rate (PIR).
Commercial EV Phase-In Rate	Supporting Adoption	Development	2025 (proposed)	Ongoing (proposed)	Rate for demand-billed customers with multiple tiers based on load factor with % of bill based on kW vs kWh increasing as load factor increases
RTS Bus Make-Ready Program	Supporting Adoption	Implementation	2021	2026	Incentives toward cost of installing and interconnecting new EV charging infrastructure (electrical infrastructure to support hydrogen refueling is eligible)
MHD EV Make-Ready Pilot	Supporting Adoption	Implementation	2023	2026	Incentives toward cost of installing and interconnecting new EV charging infrastructure for MHD EV

Initiative / Program	Category	Status	Start Date	End Date	Description
Medium- & Heavy-Duty Make-Ready Program	Supporting Adoption	Development	2025 (expected)	TBD	Program design is currently being considered in an open regulatory proceeding. Order expected in 2025. MHD EV Customer Make Ready Incentives and Utility Pro-active Planning Framework and programs being considered.
Residential EV TOU Rate	Load Management	Implementation	2019	Ongoing	Residential TOU rate for deliver and supply available specifically for EV drivers
Mass Market EV Managed Charging Program	Load Management	Implementation	2023	2026	Off-bill customer incentives for charging off-peak and/or allowing charge scheduling
EV Load Management Technology Incentive Program	Load Management	Implementation	2025	Ongoing	Incentives toward cost of EV load management technologies such as energy storage
EV Commercial Load Management Program	Load Management	Development	Pending PSC Review	Ongoing	Off-bill customer incentives for charging off-peak and/or allowing charge scheduling
MHD EV Adoption & Load Forecast	Grid Readiness	Implementation	2024	2026	Vendor led study that identifies existing MHD fleets, where they are parked, rate of EV adoption, charging needs based on fleet type, and expected load based on charging needs. Strategic assessment of charging configuration to meet needs.
Proactive Planning Proceeding	Grid Readiness	Development	2024	Ongoing	Proceeding aims to ensure that utilities can support electric capacity New Yorkers adopting electric vehicles (and heating systems) by identifying necessary grid infrastructure upgrades in a timely and cost-effective manner.

<u>Current Progress</u>: Describe the current implementation as of June 30, 2025; describe how the current implementation supports stakeholders' current and future needs.

The Companies have made progress on scaling capabilities that enable increased transportation electrification by participating actively in the Joint Utilities' EV working group and continued implementation of the EV Make-Ready Programs that support and incentivize customer investments in EV infrastructure to support light-duty EVs. After an extension, the Companies expect to complete it in 2026 and aim to address infrastructure gaps, enhance accessibility for disadvantaged communities, and help the state meet its EV deployment goals.

Concurrently, the Companies are actively engaged in the state-wide Medium- and Heavy-Duty EV Make-Ready proceeding.

As part of our communications and marketing efforts to potential EV customers, we continue to develop EV web content, and are developing new tools, such as a rate calculator, to keep customers informed.

The Companies also continue to expand the use of EVs for their vehicle fleets.

Residential Managed Charging EV Program (Case18-E-0138)

On July 14, 2023, the Companies launched an EV managed charging program marketed as OptimizEV, which is available to all residential customers who own or operate an EV and meet the requirements for participation. OptimizEV provides incentives to program participants for enrolling eligible EV equipment and participating in ongoing load shifting activities / grid-beneficial behavior for a minimum of 12 months. Incentives depend on the Tier that is selected by participants' and the associated level of commitment to load shifting.

Participants are eligible to receive enrollment incentives for start-up actions in each Tier. Participation incentives are earned in each Tier according to OptimizEV requirements. Incentives are determined monthly and paid quarterly through off-bill payments.

In the Baseline Tier, participants are eligible for a one-time enrollment incentive of $25.00 for activating a networked L2 charger or EV via telematics in the Companies' web portal or mobile app and agreeing to share their charging session data with the Companies. Baseline Tier participants receive the full cost-based value for each kWh of off-peak charging in each month they achieve 80% or greater, at home off-peak charging. Participants not achieving the 80% threshold in any given month do not earn an incentive for that month but do not lose their ability to earn in the other months of the year.

In the Advanced Tier, participants are eligible for a one-time enrollment incentive of $150.00 for similar start up actions as under the Baseline Tier, but also agree to schedule their charging sessions during off-peak periods and allow the Companies to actively manage their scheduled charging sessions. Participants must also not override their managed charging schedule resulting in an on-peak charging event greater than 15 minutes, more than three (3) times per month. Advanced participants take an active role in managing their charging in collaboration with The Companies to optimize charging for maximum benefit to customers and the distribution system.

The Companies facilitate participation using two Participant Portals, a web portal and a mobile app, within which participants can track their progress and control their charging either manually or on an automated basis. The OptimizEV program engages with participants through helpful emails and an app that provides powerful insights and notifications. These communications remind them of important program participation requirements, provide reports on their historic participation, and provide recommendations to achieve peak program participation and maximum incentives.

The Companies, in collaboration with Staff and the Joint Utilities have put significant time, focus, and resources into implementing an effective managed charging program in their respective NY service areas. These efforts are reinforced by ongoing feedback from Staff and significant consultation with managed charging industry professionals. Together with increased EV adoption and with evaluation, measurement, and verification activities taking place, the program will be under continual review and iteration.

EV Make-Ready Program (Case 18-E-0138)

The EV Make-Ready Program supports stakeholders' needs for EV charging in public, workplace, and muti-unit dwellings to accommodate an increased deployment of EVs within New York State by reducing the up-front costs of installing EV charging stations. The Make-Ready incentive offsets a large portion of, or in some cases, all, of the infrastructure costs associated with preparing a site for EV charger installation.

The PSC's November 16, 2023, Order Approving Midpoint Review Whitepaper's Recommendations with Modifications marked the conclusion of a year-long midpoint review of the program, throughout which extensive stakeholder engagement, comment periods, and technical conferences were held to inform the final Order. This Order adjusted the plug targets, baseline incentives, and reporting requirements for all the utilities from their original values to the ones that would apply through the remainder of the programs. The Midpoint Order required communication standards for chargers to improve interoperability and communication capabilities. These requirements aim to ensure a positive charging experience for EV drivers and minimize the risk of stranded assets.

As of March 15, 2025, NYSEG and RG&E have supported 2,926 L2 plugs and 447 DCFC plugs through the Make-Ready Program.[76] Throughout the state, the implementation of the program has increased L2s in the state by 28,621 and DCFCs in the state by 2,440, outpacing the demand for charging based on EV registrations. Being ahead of the market in this way ensures that the current implementation will continue to support stakeholders' future needs.

EXHIBIT 2.5-2: NYSEG L2/DCFC PLUGS

NYSEG	L2					
	Up to 50%	Up to 90%	Up to 100%	Total	2025 Target	% to Target
# Plugs Committed	71	357	0	428		
# Plugs Completed	53	1,067	191	1,311		
Total Plugs	124	1,424	191	1,739	**3,526**	**49%**
	DCFC					
	Up to 50%	Up to 90%	Up to 100%	Total	2025 Target	% to Target
# Plugs Committed	3	92	52	147		
# Plugs Completed	28	107	86	221		
Total Plugs	31	199	138	368	**594**	**62%**

EXHIBIT 2.5-3: RG&E L2/DCFC PLUGS

RG&E	L2					
	Up to 50%	Up to 90%	Up to 100%	Total	2025 Target	% to Target
# Plugs Committed	21	309	98	428		
# Plugs Completed	28	570	161	759		
Total Plugs	49	879	259	1,187	**2,437**	**49%**
	DCFC					
	Up to 50%	Up to 90%	Up to 100%	Total	2025 Target	% to Target
# Plugs Committed	0	6	10	16		
# Plugs Completed	6	40	17	63		
Total Plugs	6	46	27	79	**466**	**17%**

[76] EV Make-Ready Program data as of March 15, 2025: https://jointutilitiesofny.org/ev/make-ready

Medium and Heavy-Duty Fleet Make-Ready Pilot Program (Case 18-E-0138)

To encourage reduction of diesel emissions and promote the transition to electric vehicles in the medium- and heavy-duty transportation sectors, the Medium and Heavy-Duty Fleet Make-Ready Pilot Program is available to fleet operators in New York. This pilot program provides incentives of up to 90% of utility side make-ready costs for the installation of necessary charging infrastructure and up to 50% of customer-side infrastructure costs. Vehicle depot sites must either be publicly accessible or approved for a qualified voucher incentive program to be in the pilot. To receive customer-side incentives, vehicle depot sites must be either: (1) public or (2) located within or adjacent to a DAC.

The Pilot, and other future full-scale successor programs will be important factors in stakeholders' ability to meet the aggressive policy mandates for MHD and School Bus electrification before 2035. The Pilot's primary objective is to reduce diesel emissions within DACs, so decreasing barriers to electrification for entities that serve DACs not only supports the needs of the stakeholders owning and operating MHD fleets, but also the communities throughout the state that are impacted by air quality issues.

As of March 2025, one customer has enrolled in and completed their project for the pilot program. There is interest in the program from school districts, but progress has been slow. We have communicated and had general discussions about the program with 22 school districts over the past several months. One school district has indicated that they plan to apply for the MHD Fleet Make-Ready Pilot Program.

Medium and Heavy-Duty Fleet Assessment Services (Case 18-E-0138)

The Fleet Assessment offering within the MHD Pilot Program will continue to support fleets in their electrification journey by evaluating their current vehicles and recommending suitable electric vehicles and transition timelines.

As of March 2025, the Companies have completed 57 assessments through their third-party vendor, CLEAResult, for fleet customers across its service territory that are considering transitioning their commercial fleet to electric vehicles. Almost all the participating customers have been school districts.

The Companies have also collaborated closely with NYSERDA as part of their Fleet Electrification Plan program for school district school bus fleets. This partnership includes data sharing, joint stakeholder engagement, and the development of fleet advisory services that help school districts assess readiness, identify electrification opportunities, and estimate infrastructure needs.

Demand Charge Rebate Program (Case 22-E-0236)

The Demand Charge Rebate was approved in the Demand Charge Alternatives Order in November 2023. The Demand Charge Rebate Program (DCR) provides operating cost relief for commercial EV charging customers by offsetting demand charges, thereby encouraging the development of EV charging stations and expansion of EV charging infrastructure (while reducing a significant barrier to EV charging operation). Eligible commercial EV charging customers can receive up to a 50 percent rebate on their billed demand charges. As of March 2025, The Companies have received 73 total applications to participate in the program.

The Demand Charge Rebate Program is temporary and will be replaced by the EV Phase-in Rate (PIR) by October 2025. DCR Customers have or will receive communication on how to transition to the EV PIR if eligible.

Load Management Technology Incentive Program ("LMTIP") (Case 22-E-0236)

In its August 2024 Order Establishing Load Management Technology Incentive Programs, the Commission approved the Joint Utilities' proposal to repurpose the unused funds from the subset DCFC PPI program to offer incentives for load management technology for EV charging projects that are funded through other utility programs. The Companies launched a new Load Management Technology Incentive Program (LMTIP) on October 2, 2024. The program is designed to promote the integration of advanced technologies that optimize electric vehicle charging demand, thereby enhancing grid reliability and efficiency. LMTIP offers incentives for EV load management technologies capable of reliably balancing, curtailing, or deferring a customer's net EV charging demand on the electric grid. Load management also helps customers manage the costs of providing EV charging.

By supporting the adoption of these technologies, LMTIP aims to mitigate the impact of EV charging on the electric grid, contributing to a more sustainable and resilient energy infrastructure in New York State. The increased grid resilience provided by load management activities is crucial for meeting the increased energy demands of a growing number of EVs on the road in the future.

As of March 2025, The Companies have had 7 applications for software and received 30 program inquiries.

Proactive Planning Proceeding (Case 24-E-0364)

The Commission established this case in its Order Establishing Proactive Planning Proceeding, issued August 15, 2024. The Commission stated that the purpose of the proceeding is to ensure that utilities can support New Yorkers adopting electric vehicles and electric heating systems by identifying necessary grid infrastructure upgrades in a timely and cost-effective manner. The Companies collaborated with other utilities to develop a comprehensive proposal for a long-term Proactive Planning Framework. This framework aligns with New York's CLCPA objectives. The Companies are committed to advancing the State of New York's electrification public policy goals.

In November 2025, the Companies submitted a petition for approval to commence the accelerated development of ten electric system upgrade projects (collectively, the "Urgent Upgrade Projects") totaling $554 million (seven projects totaling $468 million at NYSEG and three projects totaling $86M at RG&E) that are urgently needed to support the immediate capacity demands related to the electrification of building, transportation, and industrial loads.

As part of this effort, the Joint Utilities submitted a Proactive Planning Urgent Upgrade Projects Evaluation and Funding Proposal outlining the principles and framework for identifying and prioritizing distribution system upgrades required to accommodate new and expected electric vehicle and building electrification load. This filing included proposed technical criteria, planning thresholds, and coordination mechanisms to guide near- and long-term infrastructure investments, ensuring timely, efficient, and equitable grid readiness across utility territories. This supports the proactive, data-driven grid planning envisioned by the CLCPA and is intended to complement ongoing efforts under the Coordinated Grid Planning Process and other electrification initiatives.

The Joint Utilities also submitted a Long-Term Proactive Planning Framework Filing that outlines a unified, statewide approach to identifying potential load growth, evaluating grid hosting capacity, and prioritizing system upgrades in advance of customer-driven interconnection requests. The framework is intended to support more transparent, anticipatory investments in the distribution system aligned with the state's decarbonization goals under the CLCPA and to complement related efforts.

On June 12, 2025, the Commission issued the Order Addressing Urgent Upgrade Filings which authorized two of the Companies ten proposed Urgent Upgrade Projects including the NYSEG Kets Falls project and the RG&E Station 124 project. The Kents Falls project authorization included $37.1m for a 30 MW capacity increase and the Station 124 project authorized $33.2m for a 47 MW capacity increase. A decision on the Long-Term Proactive Planning Framework Filing is expected by Q2 2026. However, the timing is dependent on Commission decision and authorizations.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2030, identifying planned efforts and funded efforts; Describe how the *future implementation will support stakeholders' needs in 2030 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation; Described where and how plans for topic-related work and investments affect the CGPP; Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.*

Our upcoming initiatives will focus on completing investments in the Light-Duty Vehicle Make-Ready Program, including the continued deployment of both L2 and DCFC programs. Additionally, The Companies are committed to finalizing in-progress Medium- and Heavy-Duty Vehicle-related programs and initiatives. Furthermore, The Companies are actively developing several future programs and initiatives to support continued progress. Future implementation will increase the Companies' ability to measure and forecast the impact of EVs to expand on light-duty adoption and include medium- and heavy-duty adoption impacts on the electric system and potentially manage EV charging. Our planned platform technologies such as AMI, DERMS, and advanced forecasting tools will provide visibility into where new EV load is added and provide data that we will need to forecast EV loads and assess system impacts.

To support stakeholders' needs through 2028 and beyond, we have engaged and will continue to engage directly with school districts, EV fleets, groups such as BOCES and NYSERDA, and other stakeholders. Direct engagement allows us to share relevant information and plans, receive valuable feedback, identify emerging needs, and align program developments with stakeholder priorities.

Make-Ready Program (Case 18-E-0138)

Since 2020, the Companies have offered an Electric Vehicle Make-Ready Program to support the development of electric infrastructure and equipment necessary to accommodate increased deployment of EVs within New York State. The program also supports CLCPA goals, as well as New York State's zero-emission vehicle goal.

The end of program review commenced in March 2025 with a stakeholder webinar. Over the course of the review, feedback from the utilities, industry stakeholders, interest groups, and government entities will inform the next steps for a potential future program. Any future iteration of the program could be implemented from 2027 through 2030 and beyond in continued support of electric infrastructure and EVSE development, as well as meeting CLCPA and other New York State goals.

Make-Ready Incentive Programs tailored for MHD EV Fleets (Case 23-E-0070)

The Companies are currently offering a Medium- and Heavy-Duty Make-Ready Pilot Program. Program design for a full MHD Make-Ready Program with broader eligibility is currently being considered in open regulatory proceeding. MHD EV Customer Make Ready Incentives and Utility Proactive Planning Framework and programs being considered. Program execution would then take place from 2026 through 2030 and beyond.

Significantly increased investment is needed to advance to a full-scale deployment of MHD charging infrastructure, and the program that will replace the Pilot should use the learnings from the Pilot to offer incentives with fewer restrictions to use. The work needed to progress from the current Pilot to the full-scale program should include significant input from utilities and stakeholders to ensure the program design is as inclusive as possible. The utilities expect an Order authorizing a full-scale program before the end of 2026 and will operate the Pilot until the full-scale program is authorized.

This program would continue to support meeting New York State goals around the electrification of medium- and heavy-duty vehicle fleets, while also supporting fleet operators as they work toward electrifying their vehicle fleets.

EV Phase-In Rate (Case 22-E-0236)

The EV Phase-In Rate is set to replace the existing Demand Charge Rebate Program by October 2025. This initiative will help facilitate the adoption of electric vehicles by making EV charging more cost-effective for commercial customers. The EV Phase-In Rate aims to address the financial challenges associated with demand-based charges for EV charging stations. By implementing the EV Phase-In Rate, New York aims to create a more predictable and manageable cost structure for commercial EV charging station operators, thereby supporting the state's broader goals of increasing EV adoption and reducing greenhouse gas emissions.

Load Management Technologies Incentive Program (Case 22-E-0236)

The Companies also implemented the Load Management Technology Incentive Program (LMTIP) in October 2024 (described in detail in the "Current Progress" section). Program review is expected in 2025, with the current iteration of the program expected to be implemented into 2026. This program aligns with New York State's broader energy goals and will continue to promote the integration of advanced technologies that optimize EV charging demand, thereby enhancing grid reliability and efficiency in the upcoming years.

Proactive Planning Proceeding (Case 24-E-0364)

See Proactive Planning Proceeding under the *Current Progress* section for additional background information.

The Companies have submitted a joint petition for approval to commence the accelerated development of ten electric system upgrade projects (collectively, the “Urgent Upgrade Projects”) totaling $554 million (seven projects totaling $468 million at NYSEG and three projects totaling $86M at RG&E) that are urgently needed to support the immediate capacity demands related to the electrification of building, transportation, and industrial loads. On June 12, 2025, the Commission issued the Order Addressing Urgent Upgrade Filings which authorized two of the Companies ten proposed Urgent Upgrade Projects including the NYSEG Kents Falls project and the RG&E Station 124 project. The Kents Falls project authorization included $37.1m for a 30 MW capacity increase and the Station 124 project authorized $33.2m for a 47 MW capacity increase.

The utilities filed a planning framework for an annual process to support customers’ electrification needs and New York State’s clean energy policy goals. The framework proposes a 3-year process, where the utilities conduct an annual Load Assessment, followed by periods of planning and solution design, stakeholder comment periods, determination of project eligibility and prioritization criteria, and proposal and authorization of eligible projects. This framework is currently receiving public comments.

The utilities also made a filing describing a common approach to evaluating and funding more urgent projects that require construction-related activities to begin before the Proactive Planning framework begins, so the utilities are prepared and have proposed processes to meet stakeholders’ needs in the near- and long-term.

The Proactive Planning framework is designed to complement and integrate with the CGPP, resulting in a more efficient integrated resource plan for the state’s T&D systems. [77]

By establishing this proceeding, New York State aims to proactively address the challenges associated with increased electrification, ensuring that the electric grid can accommodate new energy loads while supporting the state’s clean energy goals.

FICS

Results from the Flexible Interconnection Capacity Solution, a demonstration pilot, were reported to the Commission in 2024. The Companies demonstrated a new flexible interconnection technology that aids interconnecting renewable resources to the grid efficiently and without costly upgrades to substations or transmission lines.

The solution is being explored for larger scale implementation including integrating additional resource types and flexible loads. Capacity is a challenge for utilities across the

[77] Source: https://dps.ny.gov/news/commission-announces-new-proactive-grid-planning-proceeding-prepare-new-yorks-electric-grid

state and the nation, as the demand for electrification and green technologies increases. Innovative solutions to increasing the capacity for renewable resources delivered via existing infrastructure are key to unlocking the green energy future. The demonstration proved that this automated control system ensures the grid operates within design parameters by curtailing generation when the grid is nearing a constraint threshold, allowing for increased utilization of existing infrastructure. The Companies are proposing a to file a revised FICS REV Demonstration Project Implementation Plan for DPS approval which incorporates integrating additional DER technologies through a flexible capacity auction and to integrate flexible EV charging.

While upgrading physical substations and transmission lines is still essential to increasing renewables adoption, solutions like this one will give the Companies greater grid flexibility in delivering renewable energy to customers in the future.[78] [79]

EV Load Forecasting

The Companies recently began developing more granular load forecasts. Electrification of transportation and buildings are critical solutions for achievement of CLCPA objectives. The Companies must proactively forecast where, when, and how much load is going to be added to each circuit to efficiently assess capacity needs and identify solutions such as capacity upgrades.

The Companies recently developed a granular Medium- and Heavy-Duty EV adoption and load forecast. This vendor-led study was completed in 2025 and identified existing MHD fleets, where they are parked, anticipated rate of EV adoption, projected charging needs based on fleet type, and expected load based on charging needs. The results of this forecast provide considerable insight on the magnitude of increased demand for MHD EV charging on a circuit-by-circuit basis and will be incorporated as a component of the Companies' overall load forecast to inform future planning considerations. The Companies may consider repeating this study in the future.

In 2025, the Companies will complete development of an initial highway EV charging forecast, as well as more granular residential EV adoption and load forecasts.

The Companies are developing a highway charging forecast by assessing the current ratio of DCFC to registered EVs in New York for designated interstate highway segments. Those ratios will be multiplied by the forecasted EV adoption through 2040 to identify the

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[78] Source: https://www.nyseg.com/w/nyseg-and-rg-e-demonstrate-ability-to-add-renewable-energy-onto-grid-with-flexible-interconnections

[79] Source: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B80ED4B91-0000-C839-A43C-A68BB37C01D6%7D

expected quantity of DCFC for each interstate segment. The Companies will assess demand at existing DCFC locations to inform the assumption for forecasted demand. The forecasted demand for each interstate highway segment will be allocated to each highway exit and rest area within that segment that could reasonably accommodate DCFC from a transportation perspective.

The Companies are developing granular substation level residential EV adoption forecasts that leverage the limited data that is currently available including zip code level adoption rates and demographics to better allocate utility level forecasts to specific substations.

Development and management of advanced load forecasts is a new function for the Companies and requires dedicated resources and specialized skillset to manage effectively. The 2025 Rate Case has several proposals related to advanced load forecasting. The Companies proposed three incremental FTEs to focus on advanced load forecasting and meet the needs of proactive planning for future capacity planning and achievement of the state's CLCPA goals. In addition to the proposed incremental FTEs, the Companies proposed to continue executing electrification adoption and load studies to inform its forecasts. The Companies also proposed to implement foundational advanced load forecasting software tools that will enable the production of the necessary granular load forecasts.

Commercial Managed Charging Program (CMCP)

The Companies have developed plans for a commercial Managed Charging Program (CMCP) in response to the PSC's directives under Case 22-E-0236. This initiative aims to provide incentives to eligible, participating commercial customers to manage their EV loads during off-peak times. Specifically, the Companies will offer a Peak Avoidance Incentive that incentivizes participants to reduce their EV charging demands during the program's Peak Window. All types of EV charging are eligible, including public charging, fleet and workplace charging, multi-unit dwellings, and any other market segments who take service on an eligible commercial rate.

NYSEG and RG&E will continue refining their CMCP based on stakeholder input and the outcomes of the PSC's review process, with the goal of fully implementing the program to support New York's broader objectives for EV adoption and grid modernization.

EV Roadmap

The Companies are committed to leading the way in supporting the adoption of electric vehicles. Our EV Roadmap outlines a strategic plan for the development and implementation of programs and initiatives designed to promote EV adoption. This comprehensive guide details the steps we will take to achieve our goals, in alignment with New York State's objectives for electric vehicles. Our EV Roadmap is presented in the exhibit below.

EXHIBIT 2.5-4: EV ROADMAP

Capability	Progress to Date (2021-2025)	Near Term (2025-2027)	Longer Term (2028-2029)
Supporting EV Charging Infrastructure	• Continue Make-Ready investments: • Light-Duty EV program • MHD EV Pilot • Rochester Transit Authority Bus program • L2/DCFC program	• Complete Light-Duty Make-Ready programs (2025) • Implement MHD EV Make-Ready Program • Next iteration of Light-Duty EV program	• Continue Light-Duty and MHD EV programs • EV Charging Hub
EV Readiness	• MHD EV Fleet Assessment Service • 10-year light-duty EV forecasts • MHD EV adoption and load forecasts • Proactive Planning Proceeding • Binghamton Future Grid Pilot • Ithaca Future Grid Pilot • EVSE section-level hosting capacity maps	• Market trend analysis • Update forecasts and planning with MHDV load assumptions and proactive planning measures • Proactive Planning Proceeding • Development of highway charging forecast • Development of residential EV adoption and load forecast	• Market trend analysis • Continue to update forecasts and planning • Proactive Planning Proceeding
Intelligent Integration	• OptimizEV pilot • OptimizEV Program • Demand Charge Rebate Program • Load Management Technology Incentive Program (LMTIP) • EV & Energy Storage Pilot • Developed EV Rate • Mass Market Managed Charging	• Continue EV Rate Design (EV Phase-in Rate) • Commercial Managed Charging Program • Load Management solutions • FICS pilot	• Continue EV Rate Design • Vehicle to Grid • FICS

<u>Integrated Implementation Timeline</u>: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2030. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

The Joint Utilities' Integrated Implementation Timeline is below.

EXHIBIT 2.5-5: EV INTEGRATED IMPLEMENTATION TIMELINE

EV Integration Milestones and Investments	Programs dependent on this line item	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Make-Ready Program: 18-E-0138													
Milestone: Make-Ready Program 1.0 Order													
Investment: Make-Ready Program 1.0 Implementation									(petition to continue)				
Milestone: Midpoint Review													
Milestone: Make-Ready end-of-program review	Significant Dependencies: LMTIP Pilot, Micromobility and Transit Authority Pilots, where applicable.												
Milestone: Make-Ready Program Order 2.0 (expected)													
Investment: Make-Ready Program 2.0 Implementation (expected)													
Residential Managed Charging: 18-E-0138													
Milestone: JU Residential Managed Charging Proposals													
Milestone: Resi. Managed Charging Order													
Investment: Resi. Managed Charging Program Implementation									(extension petition)				
Investment: Submetering testing accuracy research													
Milestone: TSWG reliability and accuracy report	Significant dependencies: Resi MC Program review and possible successor program												
Milestone: Resi. Managed Charging Program Review										(petition request)			
Commercial Managed Charging: 22-E-0136													
Investment: Downstate Commercial Managed Charging	Significant dependencies: MHD Make-Ready Proceeding, Make-Ready Program Order 2.0												
Milestone: Upstate Commercial Managed Charging Order													
Investment: Upstate Commercial Managed Charging													
EV Rate Design: 22-E-0236													
Milestone: DCFC PPI Order	Program ended*												
Investment: DCFC PPI Implementation	Program ended*												
Milestone: EV Rate Design Order													
Investment: Demand Charge Rebate													
Investment: Load Management Technology Incentive Program (redeployed PPI)													
Milestone: LMTIP program review	Significant dependencies: CMCPs, Make-Ready Program, MHD Make-Ready Proceeding												
Milestone: EV Phase-In Rate Order													
Investment: EV Phase-In Rate Program Implementation													
Medium- and Heavy-Duty Vehicle Make-Ready Proceeding: 23-E-0070													
Milestone: Medium- and Heavy-Duty Vehicle (MHDV) Make-Ready Proceeding Institution Order													
Milestone: MHDV Make-Ready Order	Significant dependencies: Make-Ready Program (MHD Pilot), LMTIP,												
Investment: MHDV Make-Ready Implementation													
Proactive Planning Proceeding: 24-E-0364													
Milestone: Proactive Planning Order													
Milestone: Utility Urgent Projects Filing	Significant dependencies: MHD Make-Ready Proceeding, Make-Ready Program 2.0, CMCP												
Milestone: Proactive Planning Framework													
VTOU Proceeding: 18-E-0206													
Investment: Voluntary Time of Use Rate													

<u>Risks and Mitigation</u>: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E have identified several potential risks and issues related to our EV integration and deployment efforts and have taken mitigation efforts for each risk.

Visibility into Information

- **Risk:** The Companies have limited visibility around granular data related to into adoption of electric vehicles and utilization to inform capacity needs.
- **Mitigation Measures:** The Companies are increasing data collection, forecasting studies, internal resources, and are anticipating utilizing the Proactive Planning Proceeding framework that was filed in December 2024. In 2025, the Companies have completed a Medium- and Heavy-Duty adoption and load forecast, are pursuing direct collection of EV and customer data, and will complete development of an initial highway charging forecast, as well as a residential EV adoption and load forecast.
  The Companies' 2025 Rate Case includes several proposals related to EV load forecasting. The Companies proposed adding three incremental FTEs focused on advanced load forecasting. Additionally, the Companies plan to continue implementing electrification adoption and load studies to inform their forecasts. NYSEG and RG&E also proposed implementing advanced load forecasting software tools to produce the necessary granular load forecasts.

Legislation and Policies

- **Risk:** EV infrastructure deployment is highly dependent on federal, state, and utility funding. Potential changes to current legislation and policies at the federal and/or state-level could impact timely implementation.
- **Mitigation Measures:** NYSEG and RG&E work closely with the other Joint Utilities of New York, DPS Staff, and other stakeholders to share, identify, and incorporate regulatory concerns as our initiatives are being developed and implemented.

Cost Recovery

- **Risk:** Timely cost recovery is necessary to maintain the Companies' financial health and allow NYSEG and RG&E to continue to support State policy goals.
- **Mitigation Measures:** Currently, most EV Programs being implemented by NYSEG and RG&E are recovered through EV Surcharge on customer bills. The LMTIP and Mass Market participation incentives are funded through other mechanisms. The EV Make Ready Program is the only EV Program that requires the Companies to recover Program costs through 15 and 5-year regulatory asset treatment. The Companies

have filed comments in the Commission's current Make-Ready Program Review requesting the Commission to authorize one year recovery of Make-Ready costs.

Timing and System Capacity

- **Risk:** New York's EV market is still growing, and the medium- and heavy-duty EV market is still in the initial stages of development. The current electric grid may not be equipped to handle the increased demand from widespread EV adoption, and there are areas within The Companies' service areas that already have capacity constraints. Building capacity in these areas takes time and could depend on customers' willingness to make potentially large investments.
- **Mitigation Measures:** NYSEG and RG&E continue to monitor EV markets throughout New York and in our service territory. The Companies have worked on forecasting studies and continue to develop granular forecasting capabilities to identify EV market opportunities and ensure appropriately timed investments. The Proactive Planning Proceeding framework filing, and docket also aim to help mitigate this risk. Implementation of the Load Management Technology Incentive Program and OptimizEV help with risk mitigation by shifting EV charging demand, while continued exploring FICS could allow for greater grid flexibility.

Charging Infrastructure Costs

- **Risk:** The high costs associated with installing EV charging, particularly in DACs and rural areas, may deter investment.
- **Mitigation Measures:** Implementation of Make-Ready Programs for light-duty and medium- and heavy-duty vehicles, as well as providing demand charge relief through the Demand Charge Rebate Program (and later in 2025, the EV Phase-in Rate).

Slow EV Adoption by Medium- and Heavy-Duty Fleets

- **Risk:** We expect fleets to gradually transition medium- and heavy-duty fleets to EVs over a period of several years due to vehicle replacement schedules, vehicle availability, infrastructure, and total cost of ownership.
- **Mitigation Measures:** The Companies are working to increase stakeholder outreach to develop relationships, provide useful information, and answer questions. A

primary focus has been with school district stakeholders as they begin to electrify their school bus fleets. This type of outreach is expanding into other medium- and heavy-duty fleet operators during 2025 and beyond. Expansion of the Medium- and Heavy-Duty Make-Ready Pilot Program, with program design for a full MHD Make-Ready Program with broader eligibility currently being considered in an open regulatory proceeding, could help mitigate this risk.

Technology

- **Risk:** EVSE technologies are continuing to develop, and the pace of change is increasing. The rapid pace of innovation in EV and charging technologies presents several interrelated risks for utility planning and operations, including interoperability challenges, obsolescence and compatibility issues, cybersecurity vulnerabilities, and more.
- **Mitigation Measures:** The Companies take a phased investment approach and require standardization and interoperability for integration of new technologies and systems. We are working to understand the interfacing capabilities of vendors and OEM manufacturers and intend to move technology upstream to the manufacturer as it evolves (i.e., EVSE and monitor and control equipment will be produced by the EV OEM manufacturers). The Companies also participate in standardization efforts with the Joint Utilities of New York and other stakeholders. We will continue evaluating and implementing appropriate mitigation measures as EVSE technologies continue to evolve.

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category's needs will be met over time; Describe and explain the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

Multiple categories of stakeholders are involved in development and use, with each playing a crucial role in advancing New York State's clean transportation goals. Activities and engagement with the stakeholders described below inform DSIP and other planning.

Utility Program Customers

Utility Program Customers are direct supporters of the DSIP as program participants who are eligible to receive incentives from the utilities and are most directly responsible for implementing EV integration through the adoption of EVs and EV charging technologies. Stakeholders in this category include direct residential and commercial utility account customers, EV drivers, and fleets.

Utility Companies

NYSEG and RG&E actively work together with the other Joint Utilities of New York, working together to advance state policy goals, such as CLCPA. The Companies are active participants in several JU EV working groups and work together on several current and upcoming EV Programs. The Companies participate in Joint Utilities' EV working groups, technical sessions, and conferences to develop Make-Ready plans, residential managed charging plans, medium- and heavy-duty plans, and develop EV rates and other resources and EV tools.

Government Agencies and Regulators

These entities set policies, oversee program implementation, and regulate utilities to ensure EV adoption aligns with New York's climate goals. Stakeholders in this category that The Companies work with include:

- **The Commission and DPS Staff:** Regulates NYSEG and RG&E and approves EV infrastructure programs like Make-Ready and Demand Charge Rebate programs. Weekly meetings between JU and DPS Staff.
- **NYSERDA:** Administers incentive programs and supports research on EV adoption. NYSEG and RG&E meet one-on-one monthly with NYSERDA on the ESB FEPs, and Quarterly (via JU meetings) on general ESB and other NYSERDA EV incentives.
- **NYSDOT:** Quarterly meetings with the JU for general updates on NEVI project progress.
- **New York State Department of Environmental Conservation:** Implements emission reduction policies, including regulations affecting transportation electrification, through policies and initiatives such as CLCPA.

Advocacy Groups and Nonprofits

These organizations generally advocate for policies supporting EV adoption and equitable access to charging. We meet with these groups on varying frequencies to discuss key topics such as general company activity related to EVs, rate design, NY Proactive Planning, EV programs and incentives, opportunities to participate in events, and outreach coordination.

Examples of stakeholders in this category that the Companies engage with include Sierra Club, Environmental Defense Fund, Clean Cities of Central New York, Clean Cities of Greater Rochester.

Academic and Research Institutions

The Companies are currently working on studies with Cornell University and Yale University, with an overall goal of producing better forecasts and modeling around the grid impacts of electric vehicle adoption and building electrification, which better informs policy recommendations and program development.

Local Governments and Regional Planning Agencies

The Companies engage with towns, school districts, and regional planning agencies (such as Genesee / Finger Lakes Regional Planning Council) via meetings, presentations, participation on advisory councils, and more. These groups play a critical role in deploying EV charging infrastructure throughout New York State communities.

Private Sector and Industry Stakeholders

These stakeholders are involved in the production, distribution, and servicing of EVs and charging infrastructure. They include automakers (OEMs), charging infrastructure providers, fleet operators, and load management companies.

Stakeholder input is an important part of Transportation Electrification Program strategy and development. Valuable input from stakeholders' groups that include peer utilities, market players, utility customers and EV drivers have provided valuable input into the initial EV Programs, EV Readiness Framework and development of the operational incentive programs. We consult with peer utilities, EVSE vendors and developers on a regular basis to prepare our EV proposals and engagement in EV-related dockets. NYSEG/RG&E engaged New York Power Authority ("NYPA"), several EV charging companies, load management companies, and other stakeholders in one-on-one discussions to understand their perspectives and help inform the design of our programs, as well as participation in several utility industry working groups.

As the rapidly evolving sector grows across our service territory, NYSEG/RG&E will continue to participate in stakeholder engagement as an essential part of program and rate development needed to ensure the successful implementation of current and upcoming programs and products that accelerate transportation electrification. We will engage with local businesses, municipalities, and school districts as potential site hosts on a county-by-county basis and leverage communications with local elected officials, chambers of commerce, and other organizations. Program implementation will also require close coordination with EVSE developers and vendors. We will continuously seek input and feedback from developers and vendors to help gauge opportunities for ongoing improvement. In addition, the group engages in weekly coordination with Staff on proceedings and changing requirements.

Where stakeholder-provided information is needed to support specific implementation operational outcomes, stakeholder input is formally provided through public comment periods within our active regulatory proceedings. For example, EV charging station developers and state agencies have participated by presenting in technical sessions for the EV-Make Ready Program (Case 18-E-0138).

There are specific marketing and outreach activities to ensure that customers and associated stakeholders are engaged and informed as planning, design, and implementation progress.

The Companies utilize a variety of means and methods to effectively inform and engage stakeholders as planning, design, and implementation progress so that the outputs effectively address the needs of the utility, DER developers, and stakeholders. Public comment periods in proceedings, technical conferences, working groups, and informational webinars allow for transparency and ample stakeholder comments to be considered by the utilities and Commission. Ad-hoc communication, meetings, and ongoing collaboration are also common (i.e., meetings with NYSERDA, participation in / attendance at industry forums and conferences, etc.).

NYSEG and R&GE also participate with the Joint Utilities of New York in stakeholder outreach including webinars, newsletters, and the sharing of relevant information on the Joint Utilities', NYSEG's, and RG&E's websites.

- **Stakeholder Meetings and Workshops:** The JU have held regular stakeholder meetings and public workshops to discuss EV integration, gather feedback, and address technical issues. These forums include participation from government agencies, industry representatives, and community organizations.

- **Technical Working Groups:** The JU have established technical working groups that focus on specific aspects of EV integration, such as grid impact and charging station deployment. These groups consist of experts who collaborate to develop solutions and best practices.
- **Education and Outreach:** The JU have implemented education and outreach plans to inform stakeholders about EV programs and incentives. This includes providing resources and information on their websites, as well as conducting public awareness campaigns.
- **Collaborative Partnerships:** The JU have partnered with local governments, private companies, and non-profit organizations to advance EV initiatives. These partnerships help leverage resources and coordinate efforts to promote EV adoption.
- **Regular Updates and Documentation:** The JU continuously update technical documentation and program guidelines to ensure stakeholders have access to the latest information. This includes posting meeting agendas and supporting materials online.

Through these efforts, the Joint Utilities of New York have engaged with various stakeholders to develop EV programs that meet the needs of the community and support the state's policy goals for a sustainable and efficient transition to electric transportation. Examples of stakeholder feedback gathered by JU during their engagement efforts related to EV programs include:

- **EV Make-Ready Program:** During the stakeholder feedback sessions for the EV Make-Ready Program, stakeholders highlighted the need for more accessible and strategically located charging stations. They emphasized the importance of placing chargers in underserved areas to ensure equitable access to EV infrastructure and greater incentive level baselines to reflect actual costs in the market.
- **Technical Working Groups:** In technical working group meetings, stakeholders, including technical consultants and equipment manufacturers, provided feedback on the technical specifications for EVSE proposed by the Commission including ISO 15118-2 and -20, OCPP, and J3400. They suggested improvements to streamline the queue management and interconnection process.
- **Public Workshops:** The JU partners with stakeholders like DPS and NYSERDA to host numerous webinars and workshops to educate customers like school districts about the benefits of electric school buses, available incentives, and best practices for fleet electrification. These sessions cover topics such as charging infrastructure, fleet management, and funding opportunities.

- **Customer Surveys:** Through online surveys, stakeholders provided feedback on the effectiveness of existing EV programs and suggested areas for improvement. For example, some respondents requested additional financial incentives for purchasing EVs and installing home charging stations.
- **Regular Meetings with DPS Staff:** In regular meetings with DPS Staff, the Joint Utilities share insights into market trends, program progress, and emerging technologies. They discuss the challenges faced by project developers and proposed solutions to address these issues.

These examples illustrate how the JU have actively sought and incorporated stakeholder feedback to refine and enhance their EV programs, ensuring they meet the needs of the community and align with New York State's policy goals.

Before delivering a new tool, resource, or program offering, utilities use best practices such as consulting with stakeholders to effectively deliver the intended support and avoid unintended problems. Examples include:

- Using customer satisfaction survey data to inform new or modified program designs such as participation requirements, incentive structure, or eligibility rules such as in the Residential Managed Charging Program.
- When a public comment period is open in an EV proceeding such as the review of the J3400 standards in the Make-Ready Program, the utilities may conduct informal outreach to a range of stakeholders to encourage their participation.
- When tools or processes are being created, the utilities may gauge suitability and solicit informal feedback from stakeholders to improve the solution prior to a full-scale launch, such as in the case of the School Bus Capacity Assessment in coordination with NYSED, NYSERDA, and School District customers.

All these activities are happening iteratively within proceedings such as Case 22-E-0236 (Demand Charge Rebate, Load Management Technology Incentive Program, etc.), Case 18-E-0138 (Light-Duty and Medium- and Heavy-Duty Make-Ready Programs, Residential Managed Charging Program, etc.), Case 23-E-0070 (Medium- and Heavy-Duty Program), and Case 24-E-0364 (Proactive Planning Proceeding). Stakeholders can find updates as they happen within the specific proceedings and have numerous opportunities to provide comments and engage.

NYSEG and RG&E continuously look for opportunities to engage stakeholders and are leveraging these opportunities when we find them. The Companies have worked on increasing stakeholder engagement across the many stakeholder categories and are currently in the process of developing a comprehensive engagement and outreach plan.

Many of our EV programs are associated with regulatory proceedings that are actively open. Stakeholder feedback will be incorporated into program designs and will be measured against stakeholder expectations whenever possible. We continuously engage with stakeholders on an ongoing basis and work to ensure we're building relationships that will allow stakeholders to engage with us.

Additional Detail

Utility resources and capabilities which support electric vehicle (EV) integration at all levels in the distribution system will likely be needed within the five-year planning horizon of the DSIP Update filing. While plans for integrating EVs at the bulk, local transmission, and distribution levels will now be reflected in the CGPP, the DSIP should continue to describe means and methods for planning EV integration at the distribution level.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to electric vehicle integration. Where not yet fully developed or fluid due to ongoing policy development, the DSIP Update should provide current status and planned next steps, including an anticipated timeframe, to continue making progress.

1. Using a common framework (organization, format, semantics, definitions, etc.) developed jointly with the other utilities, identify and characterize the existing and anticipated EV charging scenarios in the utility's service territory. Each scenario identified should be characterized by:
    a. *the type of location (home, apartment complex, store, workplace, public parking site, rest stop, etc.);*
    b. *the number and spatial distribution of existing instances of the scenario;*
    c. *the forecast number and spatial distribution of anticipated instances of the scenario over the next five years;*
    d. *the type(s) of vehicles charged at a typical location (commuter car, bus, delivery truck, taxi, ride-share, etc.);*
    e. *the number of vehicles charged at a typical location, by vehicle type;*
    f. *the charging pattern by vehicle type (frequency, times of day, days of week, energy per charge, duration per charge, demand per charge);*
    g. *the number(s) of charging ports at a typical location, by type;*
    h. *the energy storage capacity (if any) supporting EV charging at a typical location;*
    i. *an hourly profile of a typical location's aggregated charging load over a one year period;*

j. the type and size of the existing utility service at a typical location;
k. the type and size of utility service needed to support the EV charging use case;

The Companies' current EV adoption and load forecasts are aligned with the NYISO Gold Book. Initial assessments of the required amount of charging infrastructure to meet ZEV targets are based on the ratios identified in National Renewable Energy Laboratory's (NREL) National Plug-in Electric Vehicle Infrastructure Analysis.[80] Additionally, The Companies have used the "Electric Vehicle Infrastructure Projection Tool" published by NREL for further analysis including identification of EV load shapes.

The Companies are currently developing an enhanced forecasting methodology to better incorporate state public policy initiatives, especially electrification of the transportation and building sectors. The enhanced forecast will incorporate locational data for known EV chargers and EV purchases to improve forecasting accuracy and precision with respect to electrification trends. The Companies also continue to advance the implementation of AMI and automated load-sensing equipment on the system. Leveraging historic electrification data as adoption becomes diffuse coupled with a more granular customer usage overlaid onto system data will allow the Companies to develop more accurate electrification forecasts at the service division-or-lower level which could support future Proactive Planning studies related to EV integration and more.

The Companies currently use the NREL EVI Pro Lite Load Profile tool to assess EV load by location type. This tool estimates the following energy and peak demand by charging type:

EXHIBIT 2.5-6: DOE ALTERNATIVES FUEL DATA CENTER

Charging Type	Total Energy	Peak Demand
Home L1	32%	29%
Home L2	40%	55%
Work L1	2%	0%
Work L2	10%	2%
Public L2	14%	13%
Public L3	1%	1%

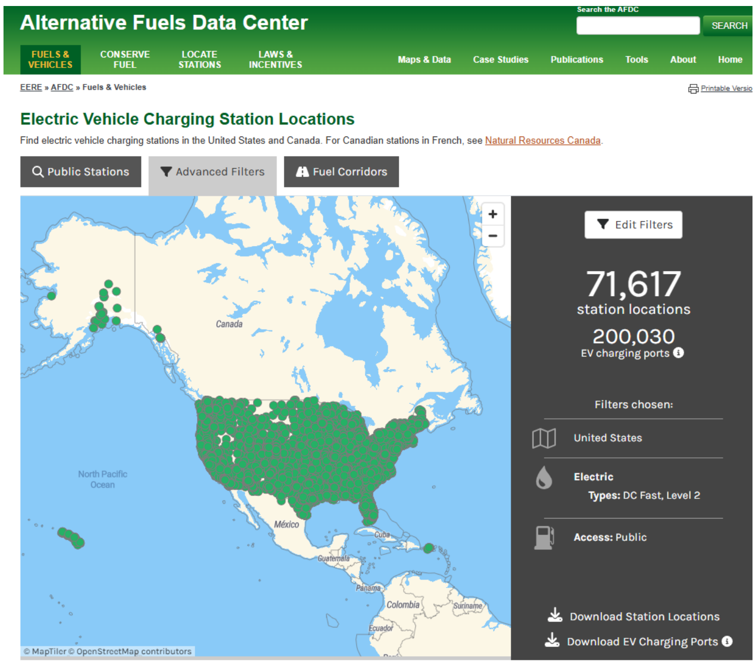
Insight into existing charging infrastructure utilizes the U.S. Department of Energy (DOE)

[80] September 2017. National Plug-In Electric Vehicle Infrastructure Analysis, US Department of Energy, Office of Energy Efficiency and Renewable Energy.

Alternative Fuels Data Center, which includes spatial data on L1, L2, and DC fast charging stations throughout the United States.[81]

This data is presented in the Exhibit 2.5-7 below.

EXHIBIT 2.5-7: DOE ALTERNATIVES FUEL DATA CENTER



Source: DOE

We use this information as inputs to support our forecasting. Additionally, we rely on various data sources such as the AFDC, the NREL EVI Pro Lite Load Profile tool, and Atlas. As new information and tools become available and validated (e.g., EPRI EVs2Scale tool, RMI GridFast tool), we may incorporate them. We are also conducting our own studies. By integrating data from customers, third-party tools, and internal studies, we aim to enhance our forecasting and make it more granular.

The Companies are also working on forecast studies (ex: medium- and heavy-duty, development of an initial highway charging forecast, and development of a residential EV

[81] DOE Alternative Fuels Data Center available here Alternative Fuels Data Center: Electric Vehicle Charging Station Locations

adoption and load forecast). As we finish deploying AMI meters in our service areas by the end of 2025, we will seek opportunities to extrapolate this data.

We engaged a vendor to develop a Medium- and Heavy-Duty EV adoption and load forecast. This included creating a base inventory of MHD fleets within the Companies' service territories by identifying publicly available records and then validating those records utilizing vehicle counts from satellite imagery. We then forecasted the rate of EV adoption of the base inventory under high, medium, and low adoptions scenarios considering the targets that have been adopted by New York State. The results of this forecast will provide considerable insight into the magnitude of increased demand for MHD EV charging on a circuit-by-circuit basis and will be incorporated into future planning considerations.

The Companies are also developing a highway charging forecast by assessing the current ratio of DCFC to registered EVs in New York for designated interstate highway segments. Those ratios will be multiplied by the forecasted EV adoption through 2040 to identify the expected quantity of DCFC for each interstate segment. The Companies will assess demand at existing DCFC locations to inform the assumption for forecasted demand.

We do not have the data or insights regarding the type(s) of vehicles charged at a typical location. We hope to use improved data and information as it becomes available to help improve our electric capacity forecasting needs to best serve our customers.

We do not have the data to specify the number of vehicles charged at a typical location by vehicle type, or the data to specify charging pattern by vehicle type at this time. Additional information will be gathered through current and upcoming EV forecasting studies and via customer AMI meter data.

The Companies utilize the DOE Alternative Fuels Data Center to acquire the number of charging ports at a typical location, by type. This information can be gathered through the DOE Alternative Fuels Data Center referenced above.

RG&E installed the 150 kW / 600 kWh energy storage system in December of 2018 at our Scottsville Road Operations Center in Rochester. The purpose of this project is to demonstrate how battery storage can be integrated with EV charging to improve project economics, minimize the impact of EV charging on the grid, and derive value from market services by pairing an ESS with two EV DC fast chargers and five level 2 chargers. We tested three use cases: building / circuit demand reduction, building load factor improvement, and demand response. By addressing the building load and DC fast charger load through battery optimization, we are relieving the circuit demand. The Company filed a Closeout Report for this REV demonstration project in Q2 2023 which included lessons learned from the project.

The Companies utilize the hourly profile generated from the NREL EVI Pro Lite tool to forecast energy and demand for a typical location. We continue to look at how to best utilize this information, along with information from our studies as inputs to inform future forecasting.

There are many circumstances that may impact the existing utility service at a new EV charger location. With relatively few charger installations today it is difficult to characterize a "typical" location. However, with federal requirements under the NEVI ("National Electric Vehicle Infrastructure") program requiring 4-150 kW chargers along highway corridors, we expect to see a typical corridor site align with federal requirements.

EXHIBIT 2.5-8: DOE NEVI-COMPLIANT PROGRAMS

Charging Type	Typical Existing Service	Required Service
Home L1	10 to 25 kva	Existing service is generally sufficient
Home L2	10 to 25 kva	Existing service is generally sufficient. May see clusters requiring upgrades in the future.
Work L1	Highly variable	Existing service is generally sufficient to meet any workplace L1 charging needs.
Work L2	Highly variable	Existing service is generally sufficient to meet any workplace L2 charging needs.
Public L2	Highly variable depending on location	A typical Public L2 location may include around 4x7.2kW chargers for which the company would generally serve with a 50 kva transformer
Public L3	Typically no existing service	NEVI Compliant site would include 4x150kW chargers which would be served by a 750 kva transformer

As mentioned earlier, the Companies are currently developing an enhanced forecasting methodology to improve accuracy and precision in predicting electrification trends across various EV charging scenarios. This methodology, along with insights from other ongoing or planned forecasting studies, helps us determine the type and size of utility services required to support different EV charging scenarios.

This detailed analysis does not address some of the characteristics requested in the subparts to this question. While the Companies continue to develop EV forecasting and load impact capabilities, forecasting methodology will need to reflect the availability of data and insights to specify a valid set of assumptions that drive the forecast results. Many of the characteristics requested in the following sub-questions require assumptions regarding aspects of the vehicle market that are not yet well understood—including travel patterns, the anticipated vehicle architecture of the market moving forward (e.g., plug-in hybrid vs battery electric), and the expected or preferred technology for charging vehicles in specific locations. The Companies have EV forecast studies in process and plans to perform additional EV forecast studies in the future, and we expect to gain additional information for improved forecasting.

2. *Describe and explain the utility's priorities for supporting implementation of the EV charging use cases anticipated in its service territory.*

The Companies have several key priorities that align with New York State's CLCPA and EV goals. These priorities include grid readiness and reliability, infrastructure expansion and accessibility, and stakeholder engagement and affordability. These priorities are reflected in the development and implementation of current and future EV programs.

Grid Readiness & Reliability

- Proactive Planning (Case 24-E-0364): Aims to ensure that utilities can support New Yorkers adopting electric vehicles by identifying necessary grid infrastructure upgrades in a timely and cost-effective manner.
- Residential Managed Charging EV Program (Case 18-E-0138), Load Management Technologies Incentive Program (Case 22-E-0236), and Commercial EV Managed Charging Program (Case 22-E-0136): These programs help (or will help when implemented) reduce peak demand impacts on the grid, incentivize off-peak charging to avoid distribution constraints, and enhance grid reliability and efficiency.

Infrastructure Expansion & Accessibility

- EV Make-Ready Program (Case 18-E-0138), Medium- and Heavy-Duty Fleet Make-Ready Pilot Program (Case 18-E-0138), MHD Make-Ready Program (Case 23-E-0070): It is important to support Make-Ready programs for public, workplace, and fleet charging, as well as prioritize equitable charger deployment in disadvantaged communities to ensure access for all. These programs support (or will support when implemented) the development of electric infrastructure and equipment necessary to accommodate the increased deployment of light-duty, medium- and heavy-duty EVs throughout New York State.

Stakeholder Engagement & Affordability

- Demand Charge Rebate Program (Case 22-E-0236), EV Phase-In Rate (Case 22-E-0236): The Demand Charge Rebate (DCR) and EV Phase-In Rate (replacing the DCR by October 2025) provide cost relief for commercial EV customers.
- All programs: The Companies utilize a variety of means and methods to effectively inform and engage stakeholders as planning, design, and implementation of programs progress so that outputs effectively address the needs of stakeholders. This is all detailed in the *Stakeholder Engagement* section.

Additional details on all the programs referenced can be found in the *Current Progress* and *Future Implementation and Planning* sections of the 2.5 EV. By focusing on the above-mentioned priorities, the Companies can effectively anticipate and support EV charging in our territory.

3. *Identify and describe all significant resources and functions that the utility and stakeholders use for planning, implementing, monitoring, and managing EV charging at multiple levels in the distribution system.*
    a. *Explain how each of those resources and functions supports the utility's needs.*
    b. *Explain how each of those resources and functions supports the stakeholders' needs.*

The Companies have two business areas that directly support electric vehicles. The Clean Energy Policy team has three FTEs that support EV strategy, analysis, program development, and stakeholder engagement. The EV Programs team has six FTEs who are responsible for implementation of the Companies portfolio of EV programs including EV Make-Ready, Managed Charging, and LMTIP. The Companies have multiple business areas that support electric vehicles through their normal functions including Customer Service who process applications for new service and answer customer billing questions, Business Relationship Managers who act as a single point of contact for certain large customers, Field Engineering who assess and design interconnection requirements for EV charging, and Distribution Planning who study the system needs and requirements for increased load. These resources will ensure that stakeholder perspectives are well understood and incorporated into all aspects of planning and implementation for beneficial electrification.

Additional resources will clearly be required to support development of granular load forecasts and implementation of our EV programs, including implementation of make-ready programs and managed charging programs, as EV charging infrastructure adoption expands.

In the recently filed Rate Cases, the Companies proposed two incremental FTEs to directly support implementation of EV programs. The two program implementation FTEs will include: 1) a manager who will be responsible for overall commercial EV infrastructure programs. They will oversee all commercial program implementation including operations, regulatory engagement, and reporting requirements. They will also supervise the staff responsible for implementation of all commercial EV related programs; and 2) a Program Manager who will lead the execution of key deliverables that support the Commercial Managed Charging Program, including managing customer enrollment, monitoring program performance, and preparing regulatory reports related to program status and progress. These two incremental positions will help drive EV charging infrastructure adoption and achievement of the State's CLCPA goals.

The Companies' integration and deployment strategy addresses stakeholder objectives to integrate and deploy EVs, with supporting infrastructure investments. We will continue to solicit the input of stakeholders in our service territory and with the Joint Utilities. NYSEG and RG&E continually update our websites with information on programs and incentives available through the Companies, as well as programs and incentives available through other stakeholders.[82]

For management and ongoing optimization of EV charging, AMI plays an important role. NYSEG and RG&E will complete the deployment of AMI in our service areas by the end of 2025. From a utility perspective, this allows The Companies to potentially monitor real-time EV charging load data. It also helps stakeholders track their energy usage at these sites and assists fleets and businesses in optimizing their charging schedules.

4. Identify the types of customer and system data that are necessary for planning, implementing, and managing EV charging infrastructure and services and describe how the utility provides those data to interested third parties.

There are several types of customer data and system data that are necessary for planning, implementing, and managing EV charging infrastructure and services.

Customer Data

- Charging Behavior: Frequency, time of day usage (peak vs. off-peak), energy consumption, charging patterns for different types of Light-Duty and Medium- and Heavy-Duty vehicles.
- Service Type and Location: Residential EV customers vs. commercial EV customers, type of dwelling (single-family, multi-unit dwelling, school bus depot, commercial location, etc.).

[82] NYSEG and RG&E.

- Participation in Utility Programs: Managed charging programs, Demand Response Program, Time-of-Use (TOU) rates.

System Data

- Infrastructure Readiness: Distribution transformer load data, substation and feeder constraints, circuit-specific constraints, etc.
- Grid Hosting Capacity: Available capacity for new charging installation.

The Companies continue to assess the customer and system data necessary for planning and managing EV charging programs. As the Companies establish a more definitive approach to the EV rollout, we plan to identify data needs and share them with third parties, consistent with our approach to sharing system data with DER developers. Developers are interested in information that helps them identify the most cost-effective locations for EVSE, including potential interconnection costs and value of charging at various times of the day. System capacity information will be available to developers through the DER portal.

5. *Describe the resources and functions needed to support billing and compensation of EV and EVSE owners/operators.*

Many of the Companies' EV programs that compensate and bill EVSE owner/operators and EV drivers currently use existing billing mechanisms or are compensated in off-bill rebate mechanisms. As programs develop into rates such as the EV Phase-In Rate, the Companies expect to modify and integrate new capabilities into the billing system and expect increased resources to support billing. For the Demand Charge Rebate and Make-Ready Programs, the NYSEG and RG&E EV Team handles the payments. Currently, the Demand Charge Rebate process is quite manual, involving searching bills by individual account, tracking them in a spreadsheet, and then entering them into Salesforce on a quarterly basis.

6. *By citing specific objectives, means, and methods describe in detail how the utility's accomplishments and plans are aligned with New York State policy, including its established goals for EV adoption.*

The Companies are committed to supporting New York State's established goals for EV adoption and CLCPA goals by expanding charging infrastructure, enabling grid readiness, and providing customer incentives. Through targeted programs, strategic partnerships, and proactive planning, NYSEG and RG&E align their efforts with state policies such as the CLCPA to facilitate widespread EV adoption and ensure a reliable, resilient grid.

New York State has set clear targets and objectives around EV adoption. To support these objectives, NYSEG and RG&E have established programs that encourage EV adoption, facilitate charging station deployment, and ensure grid preparedness for increasing EV loads.

To align with state policy, the Companies have implemented (or will implement in the future) the following types of initiatives:

- **Infrastructure Development**: Programs such as the EV Make-Ready Program support the development of electric infrastructure and equipment necessary to accommodate increased deployment of EVs within New York State.
- **Incentives & Customer Programs:** Programs such as OptimizEV provide customers with incentives while participating in load shifting activities / grid-beneficial behavior. As electric demand related to EV charging increases in the coming years, programs such as this which reduces grid stress will become more important.

To ensure effective execution and continuous alignment with state EV goals, the Companies also employ strategies around stakeholder engagement, data-driven planning, and program evaluation. Our plans and implementation are aligned with New York State policy through regulatory orders, as well as through direct customer requests that have been driven by NYS policy.

See the *Context/Background* and *Current Progress* sections for additional information.

7. *Describe the utility's current efforts to plan, implement, and manage EV-related projects. Information provided should include:*
    a. *a detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long range EV integration plans;*
    b. *the original project schedule;*
    c. *the current project status;*
    d. *lessons learned to-date;*
    e. *project adjustments and improvement opportunities identified to-date; and*
    f. *next steps with clear timelines and deliverables,*

NYSEG and RG&E are currently undertaking a suite of electric vehicle-related programs and projects designed to support statewide electrification targets and to proactively manage the evolving impacts of EV charging on the distribution system. These programs and projects span supporting EV adoption, grid and infrastructure readiness, load management, and more, and they are aligned with the Companies' long-range EV integration plans.

Our long-range plans will continue to evolve and be refined. We recognize that electrifying the transportation sector is a major contributor to the decarbonization of New York's economy. In addition to the environmental benefits, increased use of EVs can improve asset utilization by increasing non-peak electricity use which has the potential to reduce electricity rates for all customers. Current and future initiatives, as well as scheduling and current project status, are discussed in the *Current Progress* and *Future Implementation and Planning* sections above.

As mentioned in the *Context / Background* section, we have a portfolio of 13 initiatives / programs that have been proposed, are in development, or in implementation: *L2 / DCFC Make-Ready Program, Fleet Assessment Service, Demand Charge Rebate, Commercial EV Phase-In Rate, RTS Bus Make-Ready Program, MHD EV Make-Ready Pilot, MHD Make-Ready Program, Residential EV TOU Rate, Mass Market EV Managed Charging Program, EV Load Management Technology Incentive Program, EV Commercial Load Management Program, MHD EV Adoption & Load Forecast, Proactive Planning Proceeding*. Please see the Context / Background section for additional information (initiative / program category, status, start date, end date, brief description).

The Companies have learned that needs and project deployment timelines greatly vary between customers transportation electrification projects. Additionally, EV-related projects vary from typical utility customer needs. With limited reliable data in forecasting for a new customer function with the onset of an economy that is transitioning to electric transportation, planning for load that has the potential to be variable particularly in our rural regions may incur capacity constraints. We expect increased needs around collecting useful data that can inform suitable planning with ample time to prepare the grid.

We have also encountered scenarios where areas face capacity constraints, making it very costly for customers to develop large-load EV charging projects. While developers may seek more cost-effective alternative sites, customers such as school districts do not have that option. We have managed the load at some sites through lower-cost mitigation measures, such as adding cooling fans to substations or installing a recloser (as in the case of the NYPA Henrietta project site). However, these mitigations are temporary solutions, as significant and costly upgrades will eventually be required.

Our EV programs and products are developing and deploying new utility engagement tools to better serve the needs of both residential and commercial customers adopting EVs. As policy and market drivers increase customers transition to EVs, the Companies are focused on 1) ensuring available capacity for charging and 2) encouraging customer behavior that leverages the benefits of transportation electrification through traditional rate design and load management programs, as well as innovative managed charging solutions Where the Companies have gained lessons learned and best practices in serving the customers through the light-duty EV make-ready program, developing solutions to serve customers through larger load capacity projects exhibited in highway fast-charging and medium- and heavy-duty depot charging presents an opportunity for fundamental adjustments and improvements to system capacity updates and supporting programmatic utility solutions.

For the next steps associated with programs and initiatives, please see the *Future Implementation and Planning* section above for more details.

These EV-related projects demonstrate the Companies' comprehensive strategy to facilitate customer adoption of electric vehicles, ensure grid and infrastructure readiness, and align implementation with state goals. The insights gained from ongoing work are shaping future planning and programs, ensuring continued preparedness for the increasing adoption of EVs and the associated load.

8. *Describe how the utility is coordinating with the efforts of the New York State Energy Research and Development Authority (NYSERDA), the NYPA, New York Department of Environmental Conservation (DEC), and DPS Staff to facilitate statewide EV market development and growth.*

The utilities have collaborative partnerships with many state agencies who represent stakeholders to EV policy and program implementation in New York. The Joint Utilities meet regularly with DPS Staff about the implementation of the Make-Ready Program, Managed Charging Programs, LMTIP, and rate design programs. They share insights into market trends, program progress, stakeholder feedback, and emerging technologies and discuss the challenges faced by program participants and propose solutions to address these issues.

The utilities also participate in frequent meetings with state agencies like NYSERDA and NYSED to ensure coordination between utility and state incentive programs and state EV adoption mandates and policy goals. Where utility incentive programs may overlap with incentives offered from the state (such as the utility MHD Pilot and the NYSERDA NYSBIP charging voucher) utilities coordinate with the State to ensure that each incentive is appropriately awarded, and where State incentives may require utility data (such as a utility rate analysis for a site undergoing a NYSERDA Fleet Electrification Plan), the utilities have extensively collaborated with the other agency to ensure well-documented processes for information exchange.

The utilities have facilitated consistent communication with NYPA, NYSDOT and NYSERDA regarding high-profile federally funded EV charging installations that also participate in the Make-Ready program, to ensure that they move efficiently through the program to help meet the State's goals.

2.6 Clean Heat Integration

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2023 DSIP Update filing.

To implement the REV initiative, in 2015, the Commission directed utilities to file Energy Efficiency and Metrics ("BAM") Plans which proposed annual budgets and savings targets on a three-year cycle. The Commission also ordered the Utilities to file Energy Efficiency Transition Implementation Plans ("ETIPs") describing the programs and approaches that would be used to meet energy efficiency goals. These plans were approved for the period from 2016-2018. The Utilities received approval of their updated 2019-2020 plans in 2018.

In April 2018, NYSERDA and DPS filed the New Efficiency: New York whitepaper ("NE:NY Whitepaper")[83] which set a goal of statewide energy efficiency reduction of 185 trillion British thermal units ("TBtu") by 2025. The NE:NY Whitepaper also introduced a portfolio of programs and actions necessary to achieve the savings target, and if sustained, would also make up almost one-third of the state goal to reduce greenhouse gas emissions by 40% from 1990 levels by 2030. The NE:NY Whitepaper targeted increasing electrification in buildings as a key measure in hitting savings targets.

On December 13, 2018, the Commission issued its Accelerated Efficiency Order.[84] The Accelerated Efficiency Order adopted many of the NE:NY Whitepaper proposals and directed the Utilities to work amongst themselves to develop utility programs, with coordinated roles for NYSERDA. On April 1, 2019, the Joint Utilities of New York filed the New York Utilities Report Regarding Energy Efficiency Budgets and Targets, Collaboration, Heat Pump Technology and Low- and Moderate-Income Customers and Requests for Approval, which described the plan for achieving the goals outlined in the Accelerated Efficiency Order.[85] An updated report was filed on May 21, 2019.[86]

Between 2020 and 2025, NYSEG and RG&E propose heat pump savings targets of 993 and 119 giga Btu ("GBtu").

[83] Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative ("NE:NY Proceeding") New Efficiency: New York Whitepaper (filed April 26, 2018) ("NE:NY Whitepaper").

[84] NE:NY Proceeding, Order Adopting Accelerated Energy Efficiency Targets (issued December 12, 2018) ("Accelerated Efficiency Order").

[85] NE:NY Proceeding, New York Utilities Report Regarding Energy Efficiency Budgets and Targets, Collaboration, Heat Pump Technology and Low- and Moderate-Income Customers (filed April 1, 2019).

[86] NE:NY Proceeding, Updated New York Utilities Report Regarding Energy Efficiency Budgets and Targets, Collaboration, Heat Pump Technology and Low- and Moderate-Income Customers and Requests for Approval (filed May 21, 2019).

The Companies have adjusted 2024-2025 planning to prepare customers for the change in landscape coming as a result of the recent Order directing Energy Efficiency and Building Electrification Portfolios.

In this latest plan, the Companies detail the approach to 2025. In our final year the intent of the plan is to bolster current programs with **strategic measures** while phasing out programs and measures considered non-strategic. This is being done to aid in the transition to the Strategic Framework outlined in the July 2023 Midpoint review. While not required, the Commission encourages Program Administrators to start shifting away from Non-Strategic Measures & Programs in advance of 2026, to the extent pracicable.[2] The program specific descriptions (in the 2.7 energy efficiency) provides information on programs being retired early and/or measures (most notably lighting, appliances and combustion measures) that have been removed or closed out early to free us up to focus on more holistic solutions with a major emphasis on air sealing, insulation and building shell. We also plan to continue growth in beneficial electrification via the Clean Heat Program further promoting the use of heat pumps and heat pump water heaters for all sectors- large and small.

Much of the energy savings benefit then will be derived from the Clean Heat program or building electrification. Unlike traditional energy efficiency programs, Building Electrification focuses more on net MMBTU reductions by transitioning homes from combustion heating (oil, gas propane) to electric heating via heat pump technology. While there are some homes that will switch from traditional inefficient electric resistance heating the emphasis on Clean Heat will result in a decline in overall MWh reductions beginning in 2026.

EXHIBIT 2.6-1: NYSEG AND RG&E PROPOSED HEAT PUMP SAVINGS TARGETS (2020-2025)

Operating Company	Proposed GBtu Savings Target
NYSEG	992.7
RG&E	119.2

The exhibit above summarizes NYSEG and RG&E's total target of 1,112 GBtu in savings. Alongside Utility spending, NYSERDA proposed to fund low-and-moderate-income ("LMI") heat pump projects and pilots through the Clean Energy Framework ("CEF").[87] Within the filing, the New York Utilities described their proposal regarding the policy framework to develop the New York heat pump market that the Commission introduced within its Energy Efficiency Order. These five principles include:[88]

1. Drive market scale to produce cost reductions.
2. Provide a clear and stable market signal.
3. Ensure incentive structure is simple and workable from the customer perspective.
4. Pursue uniformity and flexibility across Utilities.
5. Strive for a gradual transition from existing programs.

On July 18, 2019, the Governor signed the Climate Leadership and Community Protection Act, which put into law the NE:NY Whitepaper savings target of 185 TBtu in the context of broader economic climate goals.[89]

On January 16, 2020, the Commission issued its Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025 ("NE:NY Order"). The NE:NY Order adopted a statewide heat pump target of a minimum of 3.6 TBtu through 2025. The NE:NY Order also initiated a long-term heat-pump strategy, which directed the New York Utilities and NYSERDA to develop complementary programs with meaningful market-enabling development of workforce, supply chain, and consumer demand. Finally, the NE:NY Order directed Staff to initiate a formal review of programs, budgets, and targets, no later than by the end of 2022, for consideration throughout 2023.

The Joint Utilities and NYSERDA filed the statewide heat pump implementation plan on March 16, 2020 and updated versions in April 90 and May 2020[91], which support customers in making the transition to energy efficient electrified space and water heating technologies

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[87] NE:NY Proceeding, Order Approving Clean Energy Framework Modifications (issued September 9, 2021).

[88] NE:NY Proceeding, NY Utilities Report Regarding Energy Efficiency Budgets and Targets, Collaboration, Heat Pump Technology, and Low-and Moderate-Income Customers and Requests for Approval (filed April 1, 2019).

[89] Climate Leadership and Community Protection Act, signed into law on July 18, 2019. Available at https://www.nysenate.gov/legislation/bills/2019/S6599

[90] April 30, 2020. NYS Clean Heat: Statewide Heat Pump Program Implementation Plan. Case 18-M-0084. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bC8B4A2CD-CF7A-4149-A49B-F08DD7CAA32F%7d

[91] May 29, 2020. NYS Clean Heat: Statewide Heat Pump Program Implementation Plan. Filed by the Joint Utilities. Case 18-M-0084. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={4DCD9A46-A766-4AEC-9D11-B042B4905251}

and thereby contribute to state energy and carbon reduction targets laid out in the January 2020 Energy Efficiency ("EE") Order. The implementation plan is updated annually in conjunction with Clean Heat program manual revisions. A statewide evaluation, measurement, and verification study of heat pump activities was completed June 2022.

On September 15, 2022, the Commission issued its Order Initiating The New Efficiency: New York Interim Review and Clean Energy Fund Review[92], which initiated the NE:NY Interim Review to assess the Utilities progress towards and NE:NY targets and CLCPA goals. DPS Staff filed its Energy Efficiency and Building Electrification Report ("EE/BE Report") on December 19, 2022, which summarized the performance of Statewide energy efficiency and building electrification programs. Staff also provided guidance and solicited questions on future programs, budgets, and targets. In April 2022, the Joint Utilities provided comments and answers in response to the EE/BE Report.

Current Progress: Describe the current implementation as of June 30, 2025 describe how the current implementation supports stakeholders' current and future needs.

The Companies, along with the Joint Utilities, developed a statewide Clean Heat Program, which is discussed below.

Incentives

There are three main technologies that are eligible for incentives offered by the Utilities:

1. Air-Source Heat Pumps ("ASHPs") for space heating applications;
2. Ground Source Heat Pumps ("GSHPs") for space and water heating applications; and
3. Heat Pump Water Heaters ("HPWHs") for domestic and commercial water heating applications.

The Utilities provide different incentive structures for the different building structures, which includes residential (one to four units), multifamily (five or more units), small commercial businesses ("small commercial"), and large commercial and industrial

[92] Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative. Order Initiating The New Efficiency: New York Interim Review and Clean Energy Fund Review. (issued and effective September 15, 2022. Available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A11BC600-3F96-45D3-9E2B-CD3DF9F6820D}

buildings (“C&I”). Customers may receive heat pump incentives regardless of what heating fuel was previously used.

The New York State (“NYS”) Clean Heat Program incentives are designed to promote heat pump adoption in New York focusing on market transformation and accessibility. The incentives that are offered vary by technology and category: a fixed dollar amount per unit, per system capacity, per dwelling unit, per Clean Heat project, or per annual energy savings.

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RG&E Clean Heat program exceeded its 2024 annual MMBtu savings goal. This resulted in greater spend, while maintaining the originally budgeted cost of savings. NYSEG Clean Heat program maintained its goal in 2024 for annual MMBtu while maintaining budget spend. The programs focused on the continued development of the participating contractor and implementation partner network. The Companies’ participating contractor network continued to see growth in 2023. Both NYSEG and RG&E saw substantial growth in ASHP installations, which constituted 80% of total savings for the year. Overall, in 2023 the Companies saw an increase in heat pump adoption, resulting in a 25% increase in MMBtu savings from 2022.

Marketing Efforts

NYSEG and RG&E Clean Heat Marketing Plan has 4 key features to create awareness for customer awareness expansion and technologies for space condition and water heating.

Focus on Maximizing the Benefits of Heating with Heat Pumps: NYSEG and RG&E are coordinating with NYSERDA and other Utilities on Clean Heat marketing efforts. One of the primary focuses of the outreach campaign is the emphasis on the environmental benefits of heat pumps, in addition to the economic benefits, when used for heating.

Market Channel Focus: Considering the wide breadth of heat pump usage across the major market sectors, it’s important to clearly inform customers of the specific heat pump technologies that would be applicable for their homes or businesses. In turn, market materials need to clearly identify which technologies are best suited for each type of customers. Tactics and materials inform customers of the many options and connect customers with participating contactors.

Leverage NYSERDA and Other JU Marketing Resources: NYSEG and RG&E, with support from the Implementation Contractor, continue to utilize NYSERDA’s marketing resources and resources from other Utilities to harmonize customer outreach and educational messaging and leverage resources in the development of website content, program collateral, and marketing tactics. Collaborating on marketing more cost-effectively manages program budgets and increases the effectiveness of statewide Heat Pump marketing. Additionally, the Companies collaborate with NYSERDA and Participating Contractors to access cooperative advertising support, subject to mutually development branding and messaging guideline requirements.

Focus on Contractor Education: In coordination with the Joint Efficiency Providers, NYSEG and RG&E continue to promote contractor training and education. Program success relies on an educated and motivated contractor network. This includes materials to help contractors sell full-load heat pump systems, as well as strong communications to promote training provided by NYSERDA, manufacturers, distributors, and third parties.

NYSEG and RG&E coordinate stakeholder outreach and marketing efforts in gas supply-constrained areas to help alleviate supply issues through the installation of electric heat pumps. Additionally, the Companies are considering offering an enhanced incentive in these specific areas to help drive higher rates of installation.

Exhibit 2.6-2 below shows recent policy directives and NYSEG/RG&E's as well as the Joint Utilities' actions in response.

EXHIBIT 2.6-2: HEAT PUMP POLICY DIRECTIVES AND UTILITY ACTIONS

Month/Year	Policy Guidance	NYSEG/RG&E Action	Joint Utilities Action
Dec. 2018	Utilities shall conduct EE programs consistent with the Order in 2019 and 2020	Conducted EE programs as detailed below	
Dec. 2018	Utilities shall file updated ETIPs and System Energy Efficiency Plan(s) ("SEEPs") within 60 days	Filed updated ETIP/SEEP in February 2019 and May 2020	
Dec. 2018	Utilities & NYSERDA shall file EE targets & budgets proposals by 3/31/19	Filed along with the Joint Utilities	Developed and filed EE targets & budgets
Jan. 2020	Utilities & NYSERDA shall file Heat Pump Implementation Plan by 3/16/20	Filed along with the Joint Utilities	Developed and filed plan and Program Manual with the Joint Utilities and NYSERDA
June 2022	Statewide evaluation, measurement, and verification study of heat pump activities-Released 7/2024.		
Jul. 2023	Issued: Order Directing Energy Efficiency and Building Electrification Proposals	Filed EE/BE Proposal Nov. 2023	
Dec. 2023	Staff filed request for supplemental information to EE/BE Proposals	Filed amended EE/BE Proposal Jan. 2024	
Apr 2025	Issued: Order Directing Energy Efficiency and Building Electrification		

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 20230, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2030 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation; Described where and how plans for topic-related work and investments affect the CGPP; Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

Through its market efforts and direct promotion, the Companies have made progress in meeting the State's energy savings targets through heat pump incentives and expect to make additional progress through 2025. In total, NYSEG and RG&E expect to target nearly 1 million MMBtu and 120,000 MMBtu between 2020 and 2025, respectively, as shown below.

On July 20, 2023 the Commission issued its *Order Directing Energy Efficiency and Building Electrification Proposals* ("EE/BE Order"), in which it "establishes a Strategic Framework and provides other policy guidance and administrative modifications to guide the development and implementation of post-2025 ratepayer funded EE/BE portfolios to better align with the State's climate policy objectives."[93] The EE/BE Order also directed the program administrators, including the Companies, to develop and submit budget-bounded portfolio proposals. [94]

The Companies filed an initial EE/BE Proposal ("Initial EE/BE Proposal") on November 1, 2023.[95] On December 13, 2023, Staff filed a request for supplemental information regarding EE/BE proposals ("Supplemental Information Request").[96] The Companies provided their Revised EE/BE Proposal ("EE/BE Proposal" or "Proposal"), which includes the requested supplemental information as well as additional content regarding context, programs, and plans.

This revised EE/BE Proposal includes a proposed 5-year budget representing a total investment of approximately $400 million ($279 million from NYSEG and $121 million from

[93] Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, Order Directing Energy Efficiency and Building Electrification Proposals ("EE/BE Order") (issued and effective July 20, 2023) at p. 3.
[94] Id.
[95] Case 18-M-0084, NYSEG/RG&E Energy Efficiency Portfolio Proposal 2026-2030 filed November 1, 2023 ("Initial EE/BE Proposal").
[96] Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, New York Department of Public Service EE-BE Proposal Supplemental Information Request, dated December 14, 2023 ("Supplemental Information Request")

RG&E) for 2026-2030, **with the majority of funding allocated to the Companies' highly successful NYS Clean Heat Program as well as a Residential Insulation and Air Sealing program. These budgets were developed using the five-year budget totals from the EE/BE Order.**[97]

The primary focus of the 2026-2030 portfolio is building electrification and weatherization. Pre-existing programs such as NYS Clean Heat and new programs such as Home Insulation and Air Sealing will work in concert to convert homes to heat pumps. For those customers not ready to convert heating, we encourage air sealing and insulation (in anticipation of the conversion to clean heat).

EXHIBIT 2.6-3: EE/BE PROPOSED TARGETS FOR 2026-2030

Year	Heat Pump Target (MMBtu)	
	NYSEG	RG&E
2026	608,049	129,757
2027	693,176	147,923
2028	790,221	168,632
2029	869,243	185,496
2030	912,705	194,770
2026-2030 Target Sum	***3,873,395***	***826,578***

Integrated Implementation Timeline: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2028. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

See the exhibit above for the Companies' Clean Heat targets through 2025 above.

Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E have identified the following risk that relate to meeting clean heat targets, and have taken measures to mitigate the risk, as shown in Exhibit 2.6-4.

[97] Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, EE/BE Order, Appendix at p. 100.

EXHIBIT 2.6-4: CLEAN HEAT RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
Timing: The NENY order and associated budgets/targets are only in effect through December 31, 2025. There is a need to transition the existing market to a new program structure that is in place and ready for new projects starting January 1, 2026	• Holding regular JU meetings to account for changes to the program and preparing the market for new or revised offerings Engage with key stakeholders early in the process to establish guidelines that will be in place January 1, 2026
Stakeholder Education: consistent changes to program requirements can cause confusion in the marketplace	• Quarterly participating contractor and industry partner meetings coinciding with the release of program updates • Gathering of all required program documentation in one place - Clean Heat Connect - NYS Clean Heat. Website is being updated regularly to reflect program revisions and best practices in the field
Product Availability: Limited product availability for Program qualified measures.	• Weekly technical consideration calls with the JU to establish standards for innovative technology • Bi-annual program manual updates to capture new technology that can be incentivized properly
Quality Installations: Impacting Customer experience with Heat Pump Technology	• QA/QC sub-committee jointly administered by the Joint Management Committee ("JMC") along with increased contractor engagement and outreach to ensure I quality of installation skills.

The JU conducted an analysis to quantify the energy savings necessary to stay on track with the Climate Scoping Plan's goals and to assess the contribution of existing policy incentives and interventions toward meeting that goal. NYSEG and RG&E are reevaluating their EE, LMI, and Clean Heat portfolios to be in step with the market and to utilize more complex, strategic solutions to impact harder-to-reach customers. As clean heat initiatives scale with State goals, the Companies may require additional resources to support program expansion. As an immature market, there are a variety of factors that may impact the pace of adoption of clean heat technology, such as more established alternatives, lack of public knowledge on operation and maintenance, and economic considerations. The Companies continue to focus on customer and contractor engagement in order to bolster this market. Within the Clean Heat Program, the Companies are addressing cost concerns through its rebate program. In addition, the Companies are coordinating with State efforts to grow a quality skilled labor force and continuously grow the pool of clean heat technology contractors. This may enable electrified heating technologies to be offered, similar to traditional heating solutions, when a customer decides to upgrade or replace their current systems. In order to realize the full energy and cost savings potential of building electrification, the Companies will also be expanding its weatherization offerings. Weatherization upgrades reduce energy loss through building envelopes enhancements, primarily by increasing insulation and sealing air leaks, and are an important consideration to enhance EE savings impact. The Companies are exploring opportunities to combine these home improvements with other program offerings making it truly a whole home experience. This will be beneficial to both the customer's realized savings and the net load of beneficial electrification on the electric grid. The Companies, along with the State, are just starting to investigate the potential of UTENs and NPAs. Hence, a lot of unknowns exist with both initiatives. The Companies plan to gather as much data as possible with respect to each initiative to develop improvements.

<u>Stakeholder Engagement</u>: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category's needs will be met over time; Describe and explain the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

The JMC, which is responsible for reviewing and maintaining the NYS Clean Heat Statewide Heat Pump Program, follows a process for making ongoing changes to program areas including incentive structure, eligible technologies, program rules, and other features in order to be responsive to technology and market developments and to maintain market confidence and stability. Starting in May 2021, the Joint Management Committee began a regularly recurring Participating Contractors and Industry Partners ("PCIP") Working Group Series webinar that is open to all industry program participants. This quarterly webinar is a public forum for stakeholders to introduce topics for discussion for a larger audience and provide specific program and project feedback, as well as for the JMC members to share key program updates and changes. While the PCIP webinars will serve as the primary avenue for stakeholder engagement, stakeholders also reach out to the Program Administrators directly for specific issues as well.

The Companies provide various tools to stakeholders to facilitate clean heat integration. Through the Companies' NYS Clean Heat Rebate Program webpages, stakeholders can find links to a heat pump planner tool to determine which heat pump system may be best for a residence by answering several questions. Other information provided includes a heat pump buying guide, a list of the statewide heat pump incentives and a link to a tool to locate clean heat contractors. The tool provides assistance in finding a contractor by allowing users to filter by utility, specialty, and/or county served.

The Joint Efficiency Providers implement continuous improvement practices to make implementation more efficient, make communication clearer, and to respond to participant feedback and market developments. The Joint Efficiency Providers continue to analyze program data and seek feedback from Participating Contractors and Industry Partners to evaluate potential incentive changes. The Joint Efficiency Providers continue to collaborate with technical experts, manufacturers, and other industry partners to explore and expand the range of technologies eligible for incentives. Existing and planned process improvements are detailed in the New York State Clean Heat Program Annual Report filed by the Joint Utilities.

Additional Detail

Implementing the utility resources and capabilities that enable DER interconnections to the distribution system are a critical early objective. Many of the details which identify and characterize those resources and capabilities are being worked out by the Interconnection Technology Working Group ("ITWG") and the Interconnection Policy Working Group ("IPWG") which are stakeholder collaboratives led jointly by Staff and NYSERDA. The goal of both working groups is to establish the requirements for standard resources, *processes, specifications, and policies which foster efficient, timely, safe, and reliable DER interconnections.*

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to DER interconnections:

1. *Using a common framework (organization, format, semantics, definitions, etc.) developed jointly with the other utilities, identify and characterize the existing and clean heat installation scenarios in the utility's service territory. Each scenario identified should be characterized by:*

Please see the table below for responses. However, the Companies do not have information on (e) hourly profiles of aggregated clean heating load, (f) the type and size of existing utility service at a typical location, or (g) the type and size of utility service needed to support clean heating use cases.

EXHIBIT 2.6-5: CLEAN HEAT TARGET DESCRIPTIONS

Category	Description	Target Segments	Eligible Technologies	Incentive Structure	Eligibility Criteria
Space Heating and Cooling					
2	ccASHP: Full Load Heating	Residential, Multi-Family, Small-Medium Business	Minisplit Heat Pump ("MSHP"), Central ccASHP	$/10,000 Btu/h of maximum heating capacity at 5°F, as documented on the NEEP Product List Total incentive to be limited to 120% of Building Heating Load ("BHL") - e.g., Total incentive <= (Maximum Heating Capacity * 1.2 / HP Sizing Ratio). See Equipment Sizing Requirements in Appendix 2 of the Program Manual for additional details.	•Each unit in system must be on the NEEP Product List •Total heat pump system heating capacity is <300,000 Btu/h for all building types except Multifamily •Multifamily (5 or more units) installing heat pumps should apply for Category 4, 4a, or 4b incentives •For central ASHPs installed with a back-up furnace in the same heating system, the back-up furnace must have capacity <225,000 Btu/h •Systems sized for >120% BHL may incur further review and require justification.

Category	Description	Target Segments	Eligible Technologies	Incentive Structure	Eligibility Criteria
2a	ccASHP: Full Load Heating with Integrated Controls (inclusive of base incentive)		Minisplit Heat Pump ("MSHP"), Central ccASHP with integrated controls	$/10,000 Btu/h of maximum heating capacity at 5°F, as documented on the NEEP Product List Total incentive to be limited to 120% of BHL - e.g., Total incentive <= (Maximum Heating Capacity * 1.2 / HP Sizing Ratio). See Equipment Sizing Requirements in Appendix 2 of the Program Manual for additional details.	•Eligible projects include heat pumps that meet the full building load where the previously existing system is coupled with integrated controls •Category 2a is only available for retrofit projects of existing structures and is not available to new construction or gut rehab •To be eligible for Category 2a incentives, the integrated controls package must be connected to existing fossil fuel heating equipment and must operate the heat pump as the first stage/primary heating system •Ancillary electric heating systems are not eligible for a Category 2a incentive
2b	ccASHP: Full Load Heating with Decommissioning (inclusive of base incentive)		Minisplit Heat Pump ("MSHP"), Central ccASHP with decommissioning	$/10,000 Btu/h of maximum heating capacity at 5°F, as documented on the NEEP Product List Total incentive to be limited to 120% of BHL - e.g., Total incentive <= (Maximum Heating Capacity * 1.2 / HP Sizing Ratio). See Equipment Sizing Requirements in Appendix 2 of the Program Manual for additional details.	•Eligible projects include heat pumps that meet the full building heating load where the previously existing fossil fuel system is decommissioned •Retrofit projects are eligible; new construction and gut rehabs are not eligible •Category 2b will require submission of a decommissioning checklist, which can be found on the Contractor Resources website

Category	Description	Target Segments	Eligible Technologies	Incentive Structure	Eligibility Criteria
2e	Full Load Air-to-Water Heat Pump, for space conditioning (inclusive of base incentive)		Air-to-Water Heat Pump, for space conditioning	\$/10,000 Btu/h of heating capacity at the condition of 5°F ambient and 110°F leaving water temperature, or A5W110, as documented by the New York AWHP Qualified Product list ("AWHP QPL") Total incentive to be limited to 120% of BHL e.g., Total Incentive ≤ (Maximum Heating Capacity * 1.2 / HP Sizing Ratio). See Equipment Sizing Requirements in Appendix 2 of the Program Manual for additional details	•Eligible heat pumps must be on the NYS Clean Heat AWHP Qualified Product List ("AWHP QPL") •Eligible projects include heat pumps that meet 100% of building heating load (BHL) at design conditions. AWHPs that meet only part of the building load are acceptable if the remainder of the load is met by a separate ccASHP. •Retrofit projects, new construction, and gut rehabs are eligible •AWHPs can provide space heating alone or space heating and cooling. AWHPs can also serve domestic water heating loads but may not be sized to more than 120% of the space heating load, or BHL.
3	GSHP: Full Load Heating	Residential, Multi-Family, Small-Medium Business	GSHP	\$/10,000 Btu/h of full load heating capacity as certified by AHRI Total incentive to be limited to 120% of BHL - e.g., Total incentive <= (Full Load GLHP Rating OR Full Load GWHP Rating*1.2)/HP sizing ratio). See Equipment Sizing	• Each heat pump in the system must meet or exceed the ENERGY STAR Geothermal heat pump specification. •Console units and non-console heat pump appliances with less than 24,000 Btu/h rated full load cooling must meet or exceed the minimum efficiencies listed in Tables 6 and 7 in the program manual • Total heat pump system heating capacity is <300,000 Btu/h. •System consists only of individual appliance cooling capacity for open-loop and closed-loop GSHP

Category	Description	Target Segments	Eligible Technologies	Incentive Structure	Eligibility Criteria
				Requirements in Appendix 2 of the Program Manual for additional details.	installs <135,000 Btu/h and/or individual appliance cooling capacity for direct exchange GSHP installs ≤180,000 Btu/h
3 (Cont'd)	GSHP: Full Load Heating	Residential, Multi-Family, Small-Medium Business	GSHP	$/10,000 Btu/h of full load heating capacity as certified by AHRI Total incentive to be limited to 120% of BHL - e.g., Total incentive <= (Full Load GLHP Rating OR Full Load GWHP Rating*1.2)/HP sizing ratio). See Equipment Sizing Requirements in Appendix 2 of the Program Manual for additional details.	• Ground loops must comply with applicable New York Department of Environmental Conservation ("NY DEC"), New York City ("NYC"), and International Ground-Source Heat Pump Association ("IGSHPA") standards. • Systems sized for >120% BHL may incur further review and require justification. • Projects must be sized to meet at least 100% of the load of the project scope at design conditions and serve at least 80% of the building's total square footage. See Section 3.3.2 of the Program Manual for details. • For Water-to-Water Heat Pumps that meet both space heating and DHW loads, the WWHP size must not exceed 140% of BHL (space heating load); incentives will be capped at 120% of BHL.
3 (Cont'd)	GSHP: Full Load Heating		Ground Source Variable Refrigerant Flow Heat Pump ("GSVRF")	$/10,000 Btu/h of full load heating capacity as certified by AHRI Total incentive to be limited to 120% of BHL - e.g., Total incentive <= (Full Load GLHP Rating OR Full Load GWHP Rating*1.2)/HP sizing ratio).	•Must meet or exceed the minimum efficiencies listed in Table 8, regardless of total heating system size or individual appliance cooling capacity •GSVRF full load heating capacity is determined at 32°F entering water temperature and must be <300,000 Btu/h

Category	Description	Target Segments	Eligible Technologies	Incentive Structure	Eligibility Criteria
				See Equipment Sizing Requirements in Appendix 2 of the Program Manual for additional details.	
4	Custom Full Load Space Heating Applications	Residential, Multi-Family, Small-Medium Business, Large C&I	General	$/MMBTU of annual energy savings	• All non-Multifamily building types: total heat pump system heating capacity is >300,000 Btu/h or utilizes equipment from the following categories: Commercial unitary systems • Air Source Variable Flow Refrigerant Heat Pump (ASVRF) • Cold Climate Packaged Terminal Heat Pumps (ccPTHP) • Energy Recovery Ventilator / Heat Recovery Ventilator (ERV/HRV) • Single Package Vertical Heat Pumps (SPVHPs) • Dedicated Outdoor Air System (HP-DOAS) • Heat Recovery Chiller and Heat Pump Chiller • Multifamily buildings with over 100 dwelling units • Installed systems must satisfy the dominant HVAC load for the building, per applicable code. If the building has a higher BHL than BCL, the system must be sized to satisfy BHL. If the building has a higher BCL, the system must be sized to satisfy BCL. • Each project requires pre-approval, based on a review of projected MMBtu savings and an associated preliminary incentive amount ($/MMBtu) • Projects shall be for full-load heating systems,

Category	Description	Target Segments	Eligible Technologies	Incentive Structure	Eligibility Criteria
					except for heat recovery chiller projects.
			Central ccASHP		Equipment must be NEEP-listed
			MSHP		Systems must be constituted only of NEEP-listed equipment
			Commercial Unitary Systems/Large Commercial ASHPs		Systems must have the following characteristics: •Include individual heat pump appliances that are powered by three-phase electricity or have rated cooling capacities ≥65,000 Btu/h •Units must use multi-speed or variable speed compressors. Single speed systems are not eligible for incentives. System performance criteria: •Units between 65,000 and240,000 Btu/h cooling capacity Meet or exceed current ENERGY STAR Light Commercial HVAC Key Product Criteria for COP47 •Other efficiencies (COP17, EER, IEER) must exceed applicable code •Units with >240,000 Btu/h cooling capacity Efficiencies must exceed applicable code
4 (Cont'd)	Custom Full Load Space Heating Applications		Air Source Variable Refrigerant Flow Heat Pump ("ASVRF")	$/MMBTU of annual energy savings	System performance criteria: •Units between 65,000 and 240,000 Btu/h cooling capacity must meet or exceed current ENERGY STAR requirements for VRF Criteria for Certified Cold Climate Light Commercial Heat Pumps. •Units greater than 240,000 Btu/h cooling capacity must have efficiencies that

Category	Description	Target Segments	Eligible Technologies	Incentive Structure	Eligibility Criteria
					exceed applicable energy code
			GSHP		GSHP systems must meet or exceed the ENERGY STAR Geothermal heat pump specification efficiency requirements and exhibit any of the following characteristics: •Individual heat pump appliances powered by three-phase electricity •Individual appliance cooling capacity for closed-loop GSHP installs ≥135,000 Btu/h •Individual appliance cooling capacity for direct exchange GSHP installs ≥180,000 Btu/h Exceptions to the above eligibility criteria: •GSHP systems with <24,000 Btu/h rated full load cooling must meet or exceed the specifications in Table 7 of the program manual
			GSVRF		GSVRF systems, regardless of total heating system size or individual appliance cooling capacity, must meet or exceed the minimum efficiencies listed in Table 8 of the program manual.
			Console Type GSHPs		Console type GSHP systems, regardless of total heating system size or individual appliance cooling capacity, must meet or exceed the minimum efficiencies listed in Table 6 of the program manual.
			Cold Climate Packaged Terminal Heat Pumps ("ccPTHPs")		Eligible ccPTHPs must meet the following criteria: •Each unit in system must be listed on, or meet or exceed the criteria of, the NEEP Product List

Category	Description	Target Segments	Eligible Technologies	Incentive Structure	Eligibility Criteria
			Single Package Vertical Heat Pumps ("SPVHPs")		Eligible SPVHPs must meet the following criteria: •Manufacturer-reported COP at 5°F must exceed 1.5 (at full operating capacity) •Compressor must be variable capacity (three or more distinct operating speeds, or continuously variable) •Manufacturer reported Heat Pump output at 5°F must be a minimum of 50% of rated heating capacity at 47°F
4 (Cont'd)	Custom Full Load Space Heating Applications		Energy Recovery Ventilator / Heat Recovery Ventilator ("ERV/HRV")	$/MMBTU of annual energy savings	Eligible ERV/HRVs must meet the following criteria: •Exceed federal, state, or municipal efficiency codes or standards •Must be paired with an eligible heat pump system
			Dedicated Outdoor Air System (HP-DOAS)	$/MMBTU of annual energy savings	Eligible HP-DOAS must meet or exceed the minimum efficiency requirements set forth in ASHRAE Standard 90.1-2016 tables 6.8.1-15 and 6.8.1-16 under AHRI 920 as excerpted in Section 3.4.7 of the program manual.
			Heat Recovery Chiller and Heat Pump Chiller	$/MMBTU of annual energy savings	Equipment must be used to satisfy space heating load. Equipment used for process heating is ineligible for Clean Heat incentives. Equipment must be electrically operated and meet or exceed the minimum efficiency requirements at operating conditions set forth in ASHRAE Standard 90.1-2022 under AHRI 550/590. For Ground Loop HPCs, capacities and efficiencies must be presented consistent with ISO 153256-1 in the following two scenarios: 1. Full load performance: 77/32°F EWT full speed compressor and pumping for cooling/heating 2. Part load performance:

Category	Description	Target Segments	Eligible Technologies	Incentive Structure	Eligibility Criteria
					68/41°F EWT part speed compressor and pumping for cooling/heating
4a	Custom Heat Pump + Envelope		See Category 4, plus Window Replacements, Window Film, Wall Insulation, Continuous Insulation, Window Walls, Curtain Walls, Exterior Façade, Air Leakage Sealing, Air Barrier Continuity, Roof Insulation	$/MMBtu of annual energy savings	Eligible projects include any Category 4 heat pumps, installed at either an existing facility or new construction, that are coupled with a significant envelope upgrade. The envelope upgrade must produce a quantifiable impact on the heat pump sizing to be eligible for a packaged approach. Projects may qualify for one of two tiers of envelope upgrade improvements: Tier 1: •Existing: >5% reduction in dominant load compared to baseline •New Construction: >5% reduction in dominant load compared to baseline Tier 2: •Existing: >30% reduction in dominant load compared to baseline •New Construction: >10% reduction in dominant load compared to baseline When combined, the existing baseline will be used for calculating energy savings except for new construction projects, which should use a code baseline for savings analysis. The MMBtu savings from both the envelope measures and the heat pump measures will be paid out at the 4a rate. If a HP + Envelope upgrade also includes an eligible ERV/HRV, the ERV/HRV will also receive a Category 4a incentive. Eligible measures may include Exterior: window replacements, window film

Category	Description	Target Segments	Eligible Technologies	Incentive Structure	Eligibility Criteria
					Opaque shell: wall insulation, continuous insulation, window walls, curtain walls, exterior façade Air leakage sealing, air barrier continuity Roof insulation
4b	Custom Full Load Multifamily Space Heating Applications (5-100 dwelling units)		Category 4 Space heating technologies	$/Dwelling unit	•Multifamily buildings with 5 to 100 dwelling units installing Category 4-eligible heat pumps and supporting equipment. Projects including envelope measures should apply to Category 4a. •Retrofit, gut rehab, and new construction are eligible. •Building must have year-round occupancy •Common-area-only projects are not eligible for Category 4b •Installed systems must satisfy the dominant HVAC load for the building, per applicable code. If the building has a higher BHL than BCL, the system must be sized to satisfy BHL. If the building has a higher BCL, the system must be sized to satisfy BCL. •Projects shall be for full-load heating systems. •Applicants will follow the Custom application process and requirements (see section 4.3 of the program manual).
Water Heating					
5	Residential Rated HPWH: Retail	Residential, Multi-Family, Small-Medium Business	Residential Rated HPWHs	$/Unit	HPWHs with a Uniform Energy Factor (UEF) rating. Must meet or exceed ENERGY STAR Residential Water Heater specification.
	Residential Rated HPWH: Midstream		Residential Rated HPWHs	$/Unit	HPWHs with a Uniform Energy Factor (UEF) rating. Must meet or exceed

Category	Description	Target Segments	Eligible Technologies	Incentive Structure	Eligibility Criteria
					ENERGY STAR Residential Water Heater specification.
6	Custom Centralized Hot Water Heating Applications	Multi-Family, Large C&I	Air-to-Water and Water-to-Water Heat Pumps for Dedicated DHW	$/MMBTU of annual energy savings	The following types of centralized systems are included: •Ground-coupled water-to-water heat pumps (“WWHP”) used for DHW loads must meet or exceed ENERGY STAR Geothermal heating requirements for single phase units and applicable code for 3-phase units. •Other air-to-water or water-to-water heat pump systems used for DHW must meet applicable ASHRAE 90.1-2022 requirements using AHRI 550/590. •Commercial HPWH (rated with COPH) and residential HPWH (rated with UEF) must meet applicable ENERGY STAR requirements. Residential HPWH are eligible for Cat 6 only if they are parallel piped as a central DHW system. •Heat Recovery Chillers and Heat Pump Chillers (see eligibility requirements in section 3.4.6 of the program manual) •Systems listed in NEEA Commercial/Multifamily HPWH Qualified Products List In all cases: •Fossil fuel (heating oil, natural gas, steam generated by fossil fuel, etc.) energy consumption must be reduced by the new electric technology or application •The new electric technology or application must: •Reduce existing or baseline fossil fuel or

Category	Description	Target Segments	Eligible Technologies	Incentive Structure	Eligibility Criteria
					electric resistance annual consumption by at least 50% •In savings calculations, the fossil fuel baseline efficiency (including distribution) must equal existing or upgraded (boiler) system efficiency, as applicable •Not increase the overall annual site energy consumption •Exceed applicable minimum efficiency specifications to meet applicable codes and standards
6a	Custom Centralized Multifamily Hot Water Heating Applications (5-100 dwelling units)		Category 6 water heating technologies	$/Dwelling unit	•Multifamily buildings with 5 to 100 dwelling units installing Category 6-eligible heat pump water heating equipment and supporting equipment •Residential HPWH are eligible for Cat 6a only if they are parallel-piped as a central DHW system. •Retrofit, gut rehab, and new construction are eligible •Building must have year-round occupancy •Common-area-only projects are not eligible for Category 6a
7	GSHP Desuperheater in Category 3 GSHP Systems	Residential, Multi-Family, Small-Medium Business	Optional component to GSHP systems	$/Unit	Installed as integrated component in an eligible GSHP
8	Water-to-Water Heat Pump ("WWHP") used to meet DHW Load in Category 3 GSHP Systems	Residential, Multi-Family, Small-Medium Business	WWHP added to ground loop to meet DHW load	$/Unit	WWHP can be integrated into an eligible GSHP system as a dedicated WWHP or combined with space heating, meeting or exceeding ENERGY STAR Geothermal specifications. Must meet 100% of water heating load

Category	Description	Target Segments	Eligible Technologies	Incentive Structure	Eligibility Criteria
10	Custom Partial Load Space Heating Applications		See Category 4	$/MMBTU of annual energy savings	

a. the type of location (single family residence, multifamily residence, commercial space, office space, school, hospital, etc.);

See above for the categories, descriptions and targeted segments of clean heat programs.

b. the number and spatial distribution of existing instances of the scenario;

The number of existing installations by category can be found in the New York State Clean Heat Program 2024 Annual Report filed by the JU.[98]

c. the forecast number and spatial distribution of anticipated instances of the scenario over the next five years;

The Companies do not forecast at a granular level with regards to location and spatial distribution.

d. the type(s) of clean heat solution installed at a typical location (ASHP, GSHP, HPWH, etc.);

The categories of clean heat solutions are provided in the table above.

e. an hourly profile of a typical location's aggregated clean heating load over a one-year period;

The Companies do not currently have or forecast an hourly profile of a typical location's aggregated clean heating load over a one-year period.

[98] Available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={80AEF295-0000-CB10-82E1-07BF4F6DD33D}

f. the type and size of the existing utility service at a typical location; and

The type and size of the existing utility service at a typical location varies by location and building type.

g. the type and size of utility service needed to support the clean heating use case.

The type and size of utility service needed to support the clean heating use case depends on the level of electrification and the various size of dwelling units.

2. Describe and explain the utility's priorities for supporting implementation of the clean heating use cases anticipated in its service territory.

NYSEG and RG&E are committed to supporting the implementation of clean heating use cases through a combination of driving market scale, providing clear market signals, simplifying incentive structures, pursuing uniformity and flexibility, and ensuring a gradual transition from existing programs. These priorities are designed to align with New York State's climate goals and promote the widespread adoption of heat pump technology, ultimately contributing to a more sustainable and energy-efficient future. NYSEG and RG&E have established several priorities to support the implementation of clean heating use cases within their service territories. By promoting statewide use of heat pumps, the utilities can leverage bulk purchasing and installation efficiencies, ultimately lowering the overall cost for customers.

Providing a clear and stable market plan is essential for encouraging investment in clean heating technologies. NYSEG and RG&E achieve this by offering incentives, ensuring that customers and contractors can plan their investments and projects seamlessly. This stability helps to build trust and encourages long-term adoption of heat pumps and the program. To make the adoption of heat pumps more accessible, NYSEG and RG&E prioritize creating a simple and workable incentive structure. This involves streamlining the application process, reducing paperwork, and providing clear information on available rebates and incentives to all industry stakeholders. This minimizes barriers and provides ease in customer participation.

Uniformity and flexibility across utilities is crucial for ensuring a consistent customer experience. NYSEG and RG&E work closely with other New York utilities to standardize program offerings and procedures. This collaboration ensures that customers receive the same level of service and support, regardless of their utility provider. While, transitioning from existing programs to the new clean heating initiatives requires careful planning and execution. NYSEG and RG&E focus on gradually phasing out older programs while introducing new ones, ensuring that customers are not left without support during the transition. This approach helps to maintain continuity and build confidence in the new clean heating solutions.

3. *Identify and describe all significant resources and functions that the utility and stakeholders use for planning, implementing, monitoring, and managing clean heating at multiple levels in the distribution system.*

   a. *Explain how each of those resources and functions supports the utility's needs.*

   The program implementation team consists of 3 FTEs dedicated to all aspects of program management. The Companies utilize ICF in conjunction with other JMC members to implement the program. ICF manages the online application, payment of incentives and processing of all applications. TRC manages the QA/QC for the program and performs assessments of installations to ensure quality installs by program participating contractors.

   b. *Explain how each of those resources and functions supports the stakeholders' needs.*

   These resources support stakeholders through engagement directly in collaborative meetings or through increasing program and technology awareness with program advertising.

4. *Identify the types of customer and system data that are necessary for planning, implementing, and managing clean heating infrastructure and services and describe how the utility provides this data to interested third parties.*

Currently the program doesn't provide customer data or Personally Identfiable Information ("PII") to interested parties. Interested third parties have data related to measure counts and technologies used in the 2024 Annual Report.[99]

5. *By citing specific objectives, means, and methods describe in detail how the utility's accomplishments and plans are aligned with New York State policy, including its established goals for clean heat adoption.*

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[99] The 2022 Joint Utilities' Annual Report is available at https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={E0CC4887-0000-C417-A03D-FD2C60853794} and

Tables 3 and 4 provide a count (2022 and cumulative) of the projects by program type.

The NYS Clean Heat Program is a critical component of New York State's broader energy policy, which aims to reduce greenhouse gas emissions and promote energy efficiency. NYSEG and RG&E have aligned their objectives, means, and methods with these state goals through several key strategies. The primary objective of the NYS Clean Heat Program is to increase and advance the adoption of heat pumps, thereby reducing reliance on fossil fuels and lowering greenhouse gas emissions. This aligns with New York State's CLCPA, which sets ambitious targets for reducing emissions and increasing renewable energy usage. Specifically, the CLCPA aims for a 40% reduction in greenhouse gas emissions by 2030 and an 85% reduction by 2050.

To achieve these objectives, NYSEG and RG&E implemented a variety of means. Both utilities offer substantial financial incentives to customers who install heat pumps through the NYS Clean Heat Program through a streamlined application process. These incentives reduce the upfront costs, making heat pumps more accessible and attractive to a broader range of consumers and provide a seamless customer experience from quote to installationhttps://www.nyserda.ny.gov/All-Programs/Clean-Energy-Standard. Also, extensive marketing campaigns and educational initiatives have been launched to raise awareness about the benefits of heat pumps, especially in cold climates. These efforts include workshops, webinars, and partnerships with local organizations. The utilities continue to promote the latest heat pump technologies ensuring the most efficient and consumer-friendly adoption. NYSEG and RG&E have expanded their networks of qualified contractors, ensuring that customers have access to skilled professionals for installation and maintenance for the utmost efficiency and comfort.

From 2020 to Q2 2023, NYSEG and RG&E made significant progress towards their energy savings targets. NYSEG has achieved 460,897 MMBtu of savings, representing 46% of its target, while RG&E has achieved 109,634 MMBtu of savings, representing 92% of its target. These accomplishments demonstrate the effectiveness of their strategies and their alignment with state policy goals. Looking ahead, NYSEG and RG&E plan to continue expanding their incentive programs, enhancing customer support, and promoting the latest heat pump technologies.

6. *Describe the utility's current efforts to plan, implement, and manage clean heat-related projects. Information provided should include:*

The NY Clean Heat program started in 2020 with the intention of gaining energy savings for customers through beneficial electrification. The program was initially funded through the New Efficiency New York ("NENY") Order to 2025. From 2020-Q2, 2023, NYSEG has achieved 460,897 MMBtu of savings and RG&E achieved 109,634 MMBtu of savings. NYSEG has achieved 46% and RG&E has achieved 92% of the two NE:NY savings target.

The Companies Clean Heat team has learned that the participating contractor network is critical to program success. We see these contractors as partners in the program and work to adapt program requirements to simplify the program for their use. As well, we see them as the first line of awareness for customers with the program. Without their knowledge and guidance, customers would not gain comfort with the technology.

The program has assessed and made incentive changes for the program duration as technology developed and awareness of the program increased. Those changes will come through program manual updates.

The Companies 2026-2030 EE/BE Proposal discusses the ways in which heat pump technologies will be incentivized to further promote clean energy adoption and building electrification.

a. *a detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long-range clean heat integration plans;*

b. *the original project schedule;*

c. *the current project status;*

d. *lessons learned to-date;*

e. *project adjustments and improvement opportunities identified to-date; and*

f. *next steps with clear timelines and deliverables.*

7. *Describe how the utility is coordinating with the efforts of the NYSERDA, the New York Power Authority ("NYPA"), New York Department of Environmental Conservation ("DEC"), New York Department of Public Services ("DPS") Staff, or other governmental entities to facilitate statewide clean heat market development and growth.*

NYSEG, RG&E, and NYSERDA have implemented and are working to improve upon the statewide framework to advance the adoption of heat pump systems, integrated under the umbrella of NYS Clean Heat.

NYSEG and RG&E continue to leverage the marketing resources of NYSERDA to harmonize customer outreach and education messaging and leverage resources in the development of website content, program collateral, and marketing tactics. We continue to promote strong communications to make contractors aware of the training being provided by NYSERDA. When applicable, the Utilities work with NYSERDA on clean thermal district systems.

Additionally, the Utilities coordinate with NYSERDA on residential energy efficiency and envelope programs, including the Comfort Home initiative, by providing customer referrals, and connecting customers who receive heat pump incentives that are offered under the NYS Clean Heat Program. NYSEG and RG&E also participate in pilots with NYSERDA where available.

The New York Joint Utilities coordinate with NYSERDA on all marketing and outreach efforts. The specific components of the market development include:

- Workforce Development and Training
    - Partner with business and communities to address workforce development needs for heat pump installers, drillers, technical sales staff, architects and engineers, building new operators, and new market entrants.
- Customer Education and Engagement
    - NYSERDA and the Companies collaborate to deliver a statewide consumer awareness, education, and marketing effort to encourage heat pump adoption.

NYSERDA and NYSEG RG&E continue to collaborate in developing and evaluating LMI pilots and demonstration programs, to identify replicable models for heat pump deployment in the LMI market segment while maintaining or improving energy affordability. Other areas of collaboration include identification of target customers and affordable multifamily buildings, outreach and referrals, and marketing, education, and co-funding.

2.7 Energy Efficiency Integration and Innovation

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2023 DSIP Update filing.

The CLCPA EE goal represents nearly one-third of the total GHG emission reductions needed to achieve the statewide 40 x 30 target.[100] The Companies recognize that EE programs will play a key role in achieving the State's clean energy goals and have a comprehensive set of EE programs in place to provide customers with energy savings programs. The Companies are committed to offering EE and Demand Response ("DR") programs that prioritize carbon reduction, provide clean heating alternatives, support LMI customers and DAC, and help customers manage their energy usage.

Our EE programs are supported by investments in platform technologies. Once fully deployed, advanced meter data will provide more granularity around the impacts of EE on usage and provide additional rigor to measurement and verification of EE actions. Over time, this will allow us to design and implement better and more cost-effective programs.

The Companies continue to collaborate with NYSERDA on the NY Clean Heat program and the development of a statewide framework for LMI income customers. The Companies are working closely with NYSERDA to research, design, and deploy new energy efficiency program pilots in NYSEG's and RG&E's service territories.

The Companies will build upon the successes and lessons learned from prior years' energy efficiency programs to improve program design, structure, cost-effectiveness, and efficacy. The Companies' Energy Efficiency Portfolios will continue to drive deep energy savings for the Residential, Non-Residential (commercial, industrial, and municipal customers), and Multifamily sectors, with a special emphasis on reducing the energy burden of low-and-moderate income customers as directed in the January Order.

The Companies have adjusted 2024-2025 planning to prepare customers for the change in landscape coming as a result of the Order Authorizing Low- to Moderate-Income Energy Efficiency and Building Electrification Portfolio for 2026-2030, issued May 15, 2025, in Case 18-E-0084.

In this latest plan, the Companies detail the approach to 2025. In our final year of NE:NY, the intent of the plan is to bolster current programs with strategic measures while phasing out programs and measures considered non-strategic. This is being done to aid in the

[100] The 2015 New York State Energy Plan established a goal of 40% emissions reductions from all sources by 2030.

transition to the Strategic Framework outlined in the July 2023 Midpoint review. While not required, the Commission encourages Program Administrators to start shifting away from Non-Strategic Measures/Programs in advance of 2026, to the extent practicable.[101] The program specific descriptions below provides information on programs being retired early and/or measures (most notably lighting, appliances and combustion measures) that have been removed or closed out early to free us up to focus on more holistic solutions including air sealing, insulation and building shell.

Our plan recognizes a relative increase in planned MMBTU savings and a corresponding decrease in MWh savings planned. This is due to the significant shift from measures historically promoted to the remaining measures available (and deemed strategic) as we described in detail in our 2026-2030 Proposal.[102]

Moreover, initiating more programs (with focus on building shell) a year early allows us more time to refine program design, messaging, and outreach for 2026-2030 initiatives. To provide some scalability to this shift, the measures and programs deemed "non-strategic" accounted for 89% of all electric savings yielded from our 2022 EE portfolio. To that end, the 2025 plan recognizes a relative increase in planned MMBTU savings and a corresponding decrease in MWh savings planned. This is due to the significant shift from measures historically promoted to the remaining measures available (and deemed strategic) as we described in detail in our 2026-2030 Proposal[103]

Much of the energy savings benefit then will be derived from the Clean Heat program with a markedly sharp decline in MWh reductions beginning in 2026.

Current Progress: Describe the current implementation as of June 30, 2025 describe how the current implementation supports stakeholders' current and future needs.

The Companies offer a portfolio of EE programs that use financial incentives (such as rebates), marketing, and behavioral analysis to encourage adoption of various EE products. Since 2020 the Companies' efficiency programs have resulted in annual energy savings of over 774,000 MWh. NYSEG and RG&E each offer a diverse portfolio of electric EE programs

[101] Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, Order Directing Energy Efficiency and Building Electrification Proposals (issued and effective July 20, 2023) at p. 35
[102] Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, NYSEG/RG&E EE/BE Proposal (filed: 1/16/24) at pp. 9-14.
[103] Id at pp. 9-14.

targeted to all commercial and industrial, residential, and multi-family customer segments, including programs that target LMI customers. Current programs include:

The Companies deliver cost-effective energy efficiency programs to non-residential electric and their service territories. The Companies' Non-Residential Energy Efficiency went through minor changes. A program was removed – Self-Direct. The Small Business program went through an overhaul and 3 new programs were added to this sector in 2024:

- Commercial & Industrial Rebate Program (CIRP)
- Small Business Program (SB)
- Energy Management Partnership Program (EMP)
- Retro commissioning (RCx)
- Commercial Instant Discount Program (CIDP)

In the second quarter of 2024, the Companies launched, Commercial Instant Discount, Retro-commissioning and Energy Management Partnership. The addition of these programs is still in the very early stages. The program descriptions are listed below. The Companies are also looking to pilot an Energy Saving Trees program. The purpose of the Energy Saving Trees pilot program is to offer tree distribution to commercial customers who participate in the commercial and industrial program or the small business program. This pilot program is designed to engage and educate the customer on the importance of strategic tree planting for maximum energy savings and environmental value.

Through the Non-Residential programs, the Companies provide commercial, industrial, and municipal customers with a variety of energy efficiency services which vary by program. These include direct customer incentives (custom and prescriptive), point-of-sale incentives paid to equipment distributors and direct installation of measures. The Companies continue enhancement of existing programs by adding measures to drive more comprehensive energy savings.

Commercial and Industrial Rebate Program

Program Description

The Commercial and Industrial Rebate program (CIRP) was formally called Non-Residential Prescriptive and Custom program. The Companies decided for clarity and simplicity to change the program name to Commercial and Industrial Rebate Program. All parameters of the program remain the same. The Commercial and Industrial Rebate Program offer incentives to commercial and/or industrial (C&I) customers for improving the efficiency of their facilities through the installation of new, high-efficiency technologies and equipment to replace existing, less efficient equipment.

The Companies operate the Commercial and Industrial Rebate program in the same manner, utilizing the same vendor for both utilities, and thus for the 2019-2025 SEEP, the programs are described collectively in the same section. The primary objectives of the Commercial and Industrial Rebate program are to: a) obtain cost-effective energy savings, b) improve commercial and industrial customers' bottom line, and (c) integrate sustainability into a customer's business and facility operations. There are two options for a customer to apply for the Commercial and Industrial Rebate program. The customer can choose prescriptive or custom, both are described below.

Prescriptive:
Prescriptive incentives are fixed, pre-determined rebates offered to commercial and industrial customers who install energy-efficient equipment models of commonly found technologies in their facilities.
Custom:
Custom incentives are calculated based on site-specific engineering and cost analysis for less commonly found equipment and/or situations which warrant detailed energy analysis.

Timeframe: Ongoing

Delivery Method and Target Market

Eligible Commercial and Industrial customers can select their own contractor to install energy-efficient equipment. The Companies have established a robust and growing trade ally network for the program. The customer can review a complete list of the trade ally network to choose from. If the customer does not already have a contractor of choice, they can select a contractor through the trade ally microsite and/or also through the Companies' websites which have pdf. versions of all participating contractors. There is no minimum or maximum kilowatt ("kW") or dekatherm ("Dth") criteria for customers wishing to participate in the program. NYSEG and RG&E have no customer caps or limits to the number of rebates redeemed or incentive dollars offered. Pre-approval is required for all custom incentive applications.

Commercial, Industrial, and Municipal customers with existing facilities or new construction are eligible for the program if they are an active NYSEG or RG&E Commercial and Industrial customer who pays the Systems Benefit Charge (SBC) on their electric and/or natural gas bill or pay into the applicable cost recovery mechanism through base rates when that goes into effect. Common area portions of multifamily buildings or buildings which are not separately metered per dwelling unit are also eligible for the program.

Electric customers of NYSEG and RG&E are eligible for electric measure incentives, both custom and prescriptive. NYSEG and RG&E natural gas customers are eligible for custom and prescriptive natural gas measure incentives. If a commercial, industrial, or municipal customer is both an electric and natural gas customer of NYSEG and/or RG&E, they are eligible for both electric and natural gas measure incentives from the Company with whom they are a customer.

There is an opportunity to coordinate with Energy Management Partnership (EMP) and Retrocommissioning (RCx) programs. There will be opportunities to uncover savings that can funnel to the CIRP program from being uncovered through both programs. There is a coordination effort with CIRP, Small Business (SB) and Commercial Instant Discount Program (CIDP).

Quality Assurance/Quality Control (QA/QC)

The Companies provide QA/QC through a combination of implementation contractor activities and NYSEG/RG&E employee oversight and monitoring. The QA/QC processes and controls undertaken by the implementation contractor are designed to ensure proper project energy savings calculations and incentive payments are utilized within the Non-Residential Rebate program. Additionally, the QA/QC procedures ensure compliance with other program rules specific to the Companies' Non-Residential Energy Efficiency Program Sector. The Companies' staff monitor QA/QC compliance as part of their normal energy efficiency program management activities, including processing invoices, tracking/reporting (the Clean Energy Dashboard), and monthly project documentation audits. QA/QC compliance also includes Company staff and the Companies' evaluation contractor randomly selecting projects for intensive review and the accompaniment of implementation contractor QA/QC inspectors during their scheduled pre- and/or post-inspections to verify the contractor's compliance with the Companies' QA/QC procedures.

Planned Program Activities (through 2024)

For the 2023 program year, approximately 26,689 MWh NYSEG and 25,867 MWh RG&E electric incentives and 12,044 MMBtu NYSEG and 40,719 MMBtu RG&E gas incentives were issued to commercial customers.

Planned Program Activities (2024 - 2025)

Work with the implementation contractor to continue with the robust customer outreach and engagement which includes educational webinars on the programs; from general "program kick-off" webinars to more detailed webinars. Continue yearly trade ally advisor meeting. In Q1-25, the C&I program introduced heat recovery measures to the current catalog for customers to choose from. Mid-year 2025, an update added five more strategic offerings to the catalog, signaling the move toward a fully strategic catalog. Measures are being proposed for addition into the 2026 TRM. This initiative is taking place to ensure these measures can be placed in the commercial catalog, hence making it easier for customers to apply for strategic measures.

Small Business

Program Description

As of January 2024, the Small Business Program Direct Install and Small Business Customer Choice have merged into one. The Small Business (SB) program offers incentives to small business electric and gas customers for improving the efficiency of their facilities through the installation of new, high-efficiency technologies and equipment to replace existing, less efficient equipment. The Companies operate the Small Business Program in the same manner, utilizing the same vendor for both utilities, and thus for the 2019-2025 SEEP, the programs are described collectively in the same section. Just like the Commercial and Industrial Program the Small Business has the same objectives, just on a smaller scale. The primary objectives of the Small Business programs are to: a) obtain cost-effective energy savings, b) improve Small Business customers' bottom line, and (c) integrate sustainability into a customer's business.

Eligible small business customers can select their own contractor to install energy-efficient equipment. The Companies have established a robust and growing trade ally network for the program and have taken advantage of the network utilized by the Commercial and Industrial program. This has proven to be a great resource.
Eligible customers of NYSEG or RG&E must be small commercial customers with an active NYSEG/RG&E account who pays the Systems Benefit Charge (SBC) on their electric and/or natural gas bill or pay into the applicable cost recovery mechanism through base rates when that goes into effect. Utility customers eligible for the Small Business rebates are further defined by their consumption patterns. Eligible accounts must meet one of the following sets of criteria:

1. Customers who receive BOTH electricity and natural gas delivered by NYSEG and/or RG&E must experience an average monthly peak demand less than or equal to 110kW on the primary electric account.

2. Customers who receive ONLY electricity from NYSEG/RG&E must experience an average monthly peak demand less than or equal to 110kW on the primary electric account.

3. Customers who receive ONLY natural gas from NYSEG/RG&E must experience an annual gas consumption less than or equal to 5,000 therms on the primary gas account. These customers are only eligible for the HVAC measures. Pre-approval is required for incentive applications totaling more than $10,000. All applications over $25,000 will require approval from the Companies.

There is a coordination effort with CIRP and CIDP programs; CIDP will offer lower incentives to avoid competition between the other programs.

Quality Assurance/Quality Control (QA/QC)

The Companies provide QA/QC through a combination of implementation contractor activities and NYSEG/RG&E employee oversight and monitoring. The QA/QC processes and controls undertaken by the implementation contractor are designed to ensure proper project energy savings calculations and incentive payments are utilized within the Small Business program. Additionally, the QA/QC procedures ensure compliance with other program rules specific to the Companies' Non-Residential Energy Efficiency Program Sector. The Companies' staff monitor QA/QC compliance as part of their normal energy efficiency program management activities, including processing invoices, tracking/reporting (the Clean Energy Dashboard), and monthly project documentation audits. QA/QC compliance also includes Company staff and the Companies' evaluation contractor randomly selecting projects for intensive review and the accompaniment of implementation contractor QA/QC inspectors during their scheduled pre- and/or post-inspections to verify the contractor's compliance with the Companies' QA/QC procedures.

Planned Program Activities (through 2024)

For the 2023 program year, approximately $5,591,000 for NYSEG and $1,663,000 for RG&E in electric incentives, and $9,800 for NYSEG and $11,200 for RG&E gas incentives were issued to small business customers.

Planned Program Activities (2024 - 2025)

The Small Business Customer Choice (SBCC) pilot program merged with the former Small Business Direct Install (SBDI) Program in January of 2024 and become the Small Business Program. Franklin Energy continues to be the implementation contractor for the Small Business Program in 2024. Program activity will be coordinated with new programs to ensure alignment of incentives and measure offerings for customers.

Energy Management Partnership

Program Description

Energy Management Partnership (EMP) is a program shaped to collaborate with NYSERDA's Strategic Energy Management (SEM) Program. EMP's goal is to achieve ongoing energy savings by assisting facility managers in developing technical competency, implementing O&M improvements, and developing long-term plans to optimize consumption. The EMP program offers tools and training opportunities for the large and industrial sized customers to take advantage of strategically across their organization. This program will be run in collaboration with NYSERDA's existing SEM program. The NYSEG/RG&E customer will be offered end-to-end service which includes an energy team, cohort development and management, EMP coaching, event leadership, along with technical advice and assistance. The companies will also focus on outreach and recruitment efforts. This program aims to help the customers learn how their building operates and gives the customers the tools to manage energy within their organization. EMP has the potential to generate referrals to other NYSEG and RG&E Non- Residential Programs. The vendor will work with assigned NYSERDA implementation contractor SEM coach to identify on-site energy champion and internal stakeholders that will serve the customer. Assist EMP coach to develop change management strategies, establish sense of urgency, set goals, establish a team, and generate some quick wins.

Timeframe: Begins Q1 2024

Recruitment: Work with the existing NYSERDA program implementer to identify program sites. Identify a grouping of geographically clustered customers and size of facility. Help customers understand the level of commitment needed and assist with enrollment in the

Energy Management Partnership (EMP). Set up a continuous recruiting mechanism to engage potential customers throughout the year to ensure timely start-up of EMP engagements and provide flexibility for customers and their timing needs. Will also leverage existing relationships built through the Commercial and Industrial program to begin recruitment efforts for EMP.

Workshops: Provide in person subject-matter experts (SMEs) to present and train during the regular cohort workshops. Tailor workshop presentations to the target audience, start organizing internal teams, teach teams how to look for opportunities, and facilitate peer learning to drive implementation. Leverage teams to develop technical skills and organizational manuals. Will Collaborate with NYSERDA and have customer go through some of NYSERDA workshops

Outreach and Project follow-up: Provide an in-person dedicated energy advisor that helps customers through implementation, performs project management assistance, and supports with ongoing installation of the recommended measures. Conduct ongoing discussions with customers to help overcome obstacles and demonstrate NYSEG and RG&E support. Summarize and publicize accomplishments, elevating change-makers, to demonstrate to group what is possible. Set goals and plan for continued growth.

Large Commercial and Industrial Electric customers with buildings sized with 100,000 square feet of conditioned space or more are eligible if they are an active NYSEG or RG&E Commercial and Industrial customer who pays the Systems Benefit Charge (SBC) on their electric and/or natural gas bill or pay into the applicable cost recovery mechanism through base rates when that goes into effect.

Energy Management Partnership (EMP) expects opportunities to uncover savings that customers may not be aware of otherwise that can funnel through the Commercial and Industrial Rebate Program.

Quality Assurance/Quality Control (QA/QC)

The Companies will provide QA/QC through a combination of implementation contractor activities and NYSEG/RG&E employee oversight and monitoring within the Energy Management Partnership program. Additionally, the QA/QC procedures ensure compliance with other program rules specific to the Companies’ Non-Residential Energy Efficiency Program Sector. The Companies’ staff monitor QA/QC compliance as part of their normal energy efficiency program management activities, including processing invoices, tracking/reporting (the Clean Energy Dashboard), and monthly project documentation audits. QA/QC compliance also includes Company staff and the Companies' evaluation contractor randomly selecting projects for intensive review and the accompaniment of implementation contractor QA/QC inspectors during their scheduled pre- and/or post-inspections to verify the contractor's compliance with the Companies' QA/QC procedures.

Planned Program Activities (2024 - 2025)

Work with the implementation contractor to continue with the robust customer outreach and engagement which includes educational webinars on the program; this includes general "program kick-off" webinars to more detailed customer contact which EMP requires.

Retrocommissioning

Program Description

Retrocommissioning (RCx) is a systematic process for investigating, analyzing, and optimizing an existing building's system performance through operational and facility improvement measures, and continually confirming the performance over time. The program secures comprehensive and persistent energy savings for customers through a full-service approach that offers low-cost and no-cost-facility improvement measures that result in energy saving and load management opportunities.

The Companies operate the RCx Program in the same manner, utilizing the same vendor for both utilities. The goal and intent of the RCx Program is to leverage existing building and process controls to apply low-cost energy measures that have a ROI (Return on Investment) of under two years.

Benefits of the RCx to the customer include cost savings, improved occupant safety and comfort, enhanced operational efficiency, reduced environmental impact, regulatory compliance, and increased occupant productivity.

Delivery Method and Target Market

The RCx program will secure comprehensive and persistent energy savings for NYSEG and RG&E customers through a full-service program that offers low-cost/no-cost facility improvement measures that result in energy saving and load management opportunities. Our approach provides a long-term path to savings and support to help customers achieve advanced energy management, while removing barriers to project funding, contracting, and implementation.

Commercial and Industrial customers with existing facilities sized greeted than 100,000 square feet of conditioned space, are eligible for the program if they are an active NYSEG or RG&E Commercial and Industrial customer who pay the Systems Benefit Charge (SBC) on their electric and/or natural gas bill or pay into the applicable cost recovery mechanism through base rates when that goes into effect. Customer must be willing to invest a minimum of $5,000 worth of projects.

Large Commercial and Industrial Electric customers of NYSEG and RG&E are eligible for RCx. NYSEG and RG&E have no customer caps or limits to the number of rebates redeemed or incentive dollars offered. Pre-approval is required for all custom incentive applications.

Program began Q1 2024
The Retro Commissioning Program (RCx) expects opportunities to uncover savings that customers may not be aware of otherwise that can funnel through the Commercial and Industrial Rebate Program. The RCx Program is currently collaborating with the NYSERDA FlexTech Program to provide customers additional incentives to cover costly building study fees.

Quality Assurance/Quality Control (QA/QC)

The Companies will provide QA/QC through a combination of implementation contractor activities and NYSEG/RG&E employee oversight and monitoring within the Retro Commissioning program. Additionally, the QA/QC procedures ensure compliance with other program rules specific to the Companies' Non-Residential Energy Efficiency Program Sector. The Companies' staff monitor QA/QC compliance as part of their normal energy efficiency program management activities, including processing invoices, tracking/reporting (the Clean Energy Dashboard), and monthly project documentation audits. QA/QC compliance also includes Company staff and the Companies' evaluation contractor randomly selecting projects for intensive review and the accompaniment of implementation contractor QA/QC inspectors during their scheduled pre- and/or post-inspections to verify the contractor's compliance with the Companies' QA/QC procedures.

Planned Program Activities (2024)

No incentives have been paid yet, as this program is just starting to gain eligible customers with viable projects.

Planned Program Activities (2024 - 2025)
Work with the implementation contractor to continue with the robust customer outreach and engagement which includes educational webinars on the programs; from general "program kick-off" webinars to more detailed program information. Continue to collaborate with the NYSERDA FlexTech Program to optimize savings for our customers.

Commercial Instant Discount

Program Description

The Commercial Instant Discount Program (CIDP) is a midstream program designed to influence equipment-purchasing decisions that customers and trade allies make at the distributor point of sale. CIDP offers incentives directly to distributors and manufacturers. This enables cost reductions for customers through instant rebates on their equipment purchases at the point of sale without application paperwork and benefit from lifetime energy savings.

The Companies' CIDP utilizes the same implementation contractor for both utilities and the programs will run in the same manner. The CIDP Programs' goals are to eliminate the price gap between traditional and high efficiency equipment allowing customers to purchase higher quality and more efficient products at the checkout counter helping to overcome the initial cost barrier and to improve the process to increase distributor and customer participation by reducing market barriers to maximize savings and efficiencies.

Timeframe: Began Q2 2024

Delivery Method and Target Market

This is a point-of-sale commercial program. To minimize market confusion with distributors, the Companies align program design, measures, and incentives with the National Grid Midstream Program where applicable. As well, the Companies coordinate incentives offered within their own programs to prevent double-dipping or limits to the number of rebates redeemed or incentive dollars offered.

Electric customers of NYSEG and RG&E are eligible for electric measure incentives. There is no minimum or maximum kW criteria for customers wishing to participate in the program. NYSEG and RG&E have no customer cap.

Includes a wide variety of NY market participants targeting life sciences, pump energy index (PEI)-rated clean water pumps, foodservice equipment, and HVAC measures. The Companies engage distributors that sell to customers within the Companies' service territories. There is a coordination effort with CIRP, SB and CIDP programs.

Quality Assurance/Quality Control (QA/QC)

Once this program is active, the Companies will provide QA/QC through a combination of implementation contractor activities and NYSEG/RG&E employee oversight and monitoring. The QA/QC processes and controls undertaken by the implementation contractor are designed to ensure proper project energy savings calculations and incentive payments are utilized within the Commercial Instant Discount program. Additionally, the QA/QC procedures ensure compliance with other program rules specific to the Companies' Energy Efficiency Program Sector. The Companies' staff monitor QA/QC compliance as part of their normal energy efficiency program management activities, including processing invoices, tracking/reporting (the Clean Energy Dashboard), and monthly project documentation audits.

Residential Energy Efficiency Programs

Since 2009, the Companies have delivered cost-effective energy efficiency programs to residential electric and natural gas customers across their service territories. The Companies' 2025 Residential Energy Efficiency Sector will consist of the following programs for residential customers:

- Residential Rebate Program (planned for shutdown)
- Smart Solutions
- Behavior Program (planned for shutdown)
- Multi-Family Program
- Affordable Multi-Family Energy Efficiency Program ("AMEEP") (planned to be

transferred to NYSERDA as a statewide effort)

- Home Insulation and Air Sealing Program (new pilot).
- Residential New Construction
- Panel Box Upgrade Pilot
- NY Clean Heat Statewide Heat Pump Program
- LMI 1-4 Family Homes (Empower+ is a statewide effort with NYSERDA as the lead)
- LMI Distribution Program
- Retail Products Program
- School Kits Program

Residential Rebate Program (planned shutdown 3rd quarter 2025)

Program Description

On July 1, 2009, the Companies launched the Residential Rebate program which motivated both installers and customers to choose high-efficiency natural gas boilers and furnaces and water heaters. Incentives were also added to customers who perform furnace and/or boiler tune-ups. More recently clothes dryers, induction cooktops, pool pumps, pool heaters and thermostats were added to the roster of product offerings. Rebates are offered to encourage customers to choose energy efficient products and reduce the purchase price of qualifying equipment and services.

Eligible participants include those who have an active NYSEG or RG&E residential natural gas and/or electricity account. Rebates are valid for any customer that replaces their existing equipment or installs in a new build, high-efficiency equipment that meets program standards. Natural gas furnaces, boilers, natural gas dryers and pool pumps must be certified using the Air Conditioning, Heating and Refrigeration Institute (AHRI) or ENERGY STAR® listed.

Additional program eligibility rules are designed to ensure the installation of new, high-efficiency equipment by qualified contractors. The installation of the Wi-Fi-enabled thermostats, clothes dryers, induction cooktops and pool pumps may either be contractor or self-installed.

Design and Incentives

Contractors and customers are notified of incentive offerings through bill inserts, direct emails, and our website. Collateral material is also placed at local retail storefronts (such as The Home Depot and Lowes) where qualified product is sold. Customers are encouraged to complete an online application to receive a rebate check in the mail. A paper application is also still available should the customer require (or prefer) that option.

Delivery Method and Target Market

We target residential customers as well as installation professionals. The Companies utilize an implementation contractor to process rebate applications and payment processing, customer service (e.g., call center functions), reporting, and QA/QC activities including field verification inspections.

Program Activity and Budgets

Pool pump and pool heater promotions have been heavily focused on 1st and 2nd quarter when pool contracts are likely to be signed, and installers are not out on the job. Smart thermostats, induction cooktops and clothes dryers are promoted year-round.

Furnaces, boilers, and tune ups will not be actively promoted in 2025 since they will be phased out mid-year 2025.

QA/QC Procedures

The Companies maintain QA/QC processes and procedures to ensure the high-quality of work performed and data accuracy, including:

- Rebate application processing quality checks, including customer and equipment eligibility and non-duplication of incentives.
- Sampling of installed equipment in the field to verify installation quality and savings veracity.
- Program reporting, including regular performance reports, data needed for impact and process evaluations, and maintenance of the tracking database.

The Companies' staff monitor QA/QC compliance during their normal energy efficiency program management activities, including invoice processing, tracking/reporting (the Clean Energy Dashboard), and monthly project documentation audits. Additionally, the Companies' staff randomly select Residential Rebate program projects for periodic audits of program activities, such as customer installations and implementation contractor project documentation.

Planned Program Activities

Since the boilers and furnaces within this program are considered non-strategic the Companies plan to phase out the Residential Rebate program. The general trend will be to slowly reduce marketing of the rebates through the end of 2024 year and begin informing customers and contractors that the program will close mid-2025. Shutting down mid-year will ensure all remaining and pending incentives will be paid before January 1, 2026.

Any electric measures (identified as strategic measures) will be transitioned to the Companies Retail Products program where customers will benefit from instant in-store discounts.

Smart Solutions Electric/Gas Programs

Program Description

The Companies' Smart Solutions Marketplace, (previously called Online Energy Marketplace), is an e-commerce platform designed to facilitate the purchase of energy-saving products while offering instant rebates to customers at the point of sale. Upon confirmation of their account number, customers can purchase and receive instant rebates on the following products: smart thermostats, air purifiers, smart window air conditioners, advanced power strips, water-saving products (e.g., low-flow showerheads and aerators), weatherization products (e.g., spray foam, window film, weather-stripping, caulk, pipe insulation), as well as bundled offerings. Rebates range from as little as $1 for weatherstripping to $75 for a smart thermostat. These offerings will be available to customers through 2025.

Delivery Method and Target Market

The Companies utilize an implementation contractor to deliver services for both NYSEG and RG&E's Smart Solutions Marketplaces, including making online portal design updates, working with manufacturers to secure existing and new inventory, customer service (e.g., call center functions), reporting, and QA/QC activities. The target market includes active residential electric and natural gas customers.

Coordination with other programs

Customers can access and enroll into other programs (e.g., Home Insulation and Air Sealing, Residential Rebates, NYS Clean Heat and Empower Programs) through the "Home Services and Rebates" section of the Smart Solutions Marketplace site. Customers can also enroll directly into the Smart Savings Rewards Demand Response Program through links on each eligible thermostat product page. Eligible thermostats sold on the Smart Solutions Marketplace include Ecobee, Google Nest and Sensi thermostats.

Quality Assurance/Quality Control (QA/QC)

QA/QC processes and procedures are maintained to ensure data accuracy and a high-quality of work performed. This includes quality checks on rebates processed, verifying customer eligibility, and reviewing implementation vendor reporting and tracking (including regular requests for performance reports, periodic requests for data needed for impact and process evaluations, and ensuring the implementation vendor's tracking database is well maintained). The EM&V Manager supervises and coordinates with the evaluation vendor to perform quality assessments for a random sampling of the Smart Solutions program's project, such as equipment installations and implementation vendor project documentation.

Planned Program Activities

New products are continually added to encourage repetitive sales and meet savings goals. The weatherization product line was expanded to include weatherstripping, caulk and pipe insulation, and smart window air conditioners were added this year as well. To better serve our customers, a section called "Customer Solutions" was added to provide information on available digital solutions (e.g., eBill, Budget Billing, Auto-Pay, and the mobile app) to make it easier for customers to pay their bills and receive information from their utility.

Appliance Recycling Program (sunset 3rd quarter of 2023)

Program Description

The Appliance Recycling Program provided the convenience of free removal as well as rebates to customers who agreed to dispose of their old, inefficient refrigerators, freezers, and room air conditioners. In 2023 we experienced issues with our recycling vendor's ability to maintain adequate coverage and service of our territory.

Since recycling was deemed non-strategic (July 2023 Midpoint review,[104]) the companies elected to not seek an alternative vendor service and instead permanently closed the program. Funding previously dedicated to Appliance Recycling has been repurposed over to other programs/measures deemed strategic.

As part of the shutdown, mitigation plans were created to address all customers who were impacted. Incentive payments on the Companies' behalf were processed through the second quarter of 2024.

[104] Case 14-M-0094, Proceeding on Motion of the Commission to Consider a Clean Energy Fund and Case 18-M-0084, In the Matter of a Comprehensive Energy efficiency Initiative, Order Directing Energy Efficiency and Beneficial Electrification Proposals, (issued and effective July 20, 2023) at p. 36.

Behavioral Electric/Gas (planned shutdown Q4 2025)

Program Description

The Behavior program provides customized home energy reports ("HER") for program participants to access and track their energy usage and savings. The HERs encourage residential customers to save energy through targeted energy-saving tips and promote the Companies' traditional energy efficiency programs. Delivery Method & Target Market

Currently, the program has three customer treatment groups who were randomly selected to receive a combination of paper and digital HERs. These groups consist of dual, gas only and electric only fuel types. The control group also consists of randomly selected customers who do not receive HER reports. The monthly energy savings is measured by taking the difference in energy usage reduction between treatment and control groups. Customers who receive digital HERs are sent a report once a month for twelve months and paper HER recipients receive five-six HERs over a twelve-month period.

The free form text (FFT) section of the HERs provides an opportunity to cross promote other energy efficiency programs and customer incentives. The FFT section has been used to educate customers and provide direct access to the Smart Solutions Marketplace, Residential Rebate, Clean Heat, and the Smart Savings Demand Response programs utilizing a QR code.

Quality Assurance/Quality Control

Monthly ongoing program management involves the following: monitoring of implementation vendor reporting and tracking including regular requests for performance reports, periodic requests for data needed for impact and process evaluations, and ensuring the implementation vendor's tracking database is well maintained. The EM&V Manager supervises and coordinates with the evaluation vendor to perform quality assessments, whereby, each cohort is treated annually using treatment and control group billing data in the pre and post period to estimate program impact and reporting accuracy for each wave.

Planned Program Activities

Behavior programs have been deemed non-strategic via the July 2023 Midpoint review. Consequently, we plan to close out this program permanently as of Q4 2025.

Multifamily Electric/Gas Programs

Program Description

The Multifamily (Market Rate) program is designed to reduce usage, while increasing the value and appeal of multifamily buildings with energy-efficient upgrades and provide a more comfortable environment for tenants in the NYSEG and RG&E territories. The program provides direct-install measures for in-unit and common areas at low-to-no-cost to the customer. These measures include LED hardwired or screw in lighting, Wi-Fi and programmable thermostats, exit sign lighting, lighting controls, low-flow faucet aerators and showerheads, insulation, and pipe wrap upgrades.

Delivery Method and Target Market

The program is administered and carried out by our Implementation Contractor (IC). Program services, including free energy assessments and financial incentives in the form of low- to no-cost upgrades, are provided to program Participants who implement upgrades that improve the energy efficiency of their building(s). The IC educates property managers/owners and maintenance staff on the benefits of the upgrades provided.

Buildings can consist of 5+ residential units under one roof. The Program is also available to certain other facilities and spaces meeting eligibility parameters, such as on or off -campus Greek Life student housing and townhomes.

In the event a project does not meet the eligibility criteria established for the program, we refer the participant to other known programs that may be of assistance to the building. These options can include the NYSEG/RG&E commercial programs, Empower, the AMEEP and other LMI specific programs such as the Heating Energy Assistance Program or Weatherization Assistance Programs.

Rise Engineering is also the lead vendor for the AMEEP program. This allows them to maximize their outreach efforts and secure portfolio-wide participation assessments, and post-installation walkthroughs.

Quality Assurance/Quality Control (QA/QC)

To ensure data accuracy, our implementation contractor will schedule a site visit or will perform a desk review on a sampling of projects to verify that the work has been installed. Our installation contractor has a QC process which occurs throughout the lifecycle of the project. Elements of the ongoing QC process include pre-installation walkthrough, material verification, on-site implementation assessments, and post-installation walkthroughs.

Planned Program Activities

With the program utilizing the same IC for both the Market Rate program as well as the AMEEP program, we are continuing to see that more Market Rate buildings are qualifying for AMEEP, based on the rent roll tool used for eligibility purposes. This is resulting is a shift of Market Rate projects to AMEEP, impacting the overall spend and savings towards the Market Rate program.

Starting in 2026, many of the measures mentioned above will be phased out as they will be considered non-strategic. The future Market Rate program will focus on strategic measures, such as building shell (air sealing, insulation, windows).

In 2023, the Multifamily program began hosting webinars for members of the Trade Ally Network. This has been beneficial in educating the trade allies on the multifamily program and the incentives available in 2023 and 2024. These webinars will continue 2-3 times a year or on as-needed basis. This has prompted more trade allies to participate in the Multifamily and AMEEP programs.

The program added boiler/furnace tune up incentives for 2024. This measure was included to attract more property managers/owners to the program and would allow NYSEG and RG&E to assess more multifamily buildings.

Retail Products Electric Program

Program Description

The Companies engage directly with product manufacturers and retailers who agree to lower the purchase price of selected energy efficient products instantly at the cash register. This instant discount eliminates the obstacles associated with traditional downstream programs where customers are required to fill out a rebate application or use coupons to receive a utility incentive.

The program, originally called Retail Lighting, was renamed Retail Products in 2023 to represent the transition to more diversified (non-lighting) measures. Incentives on ENERGY STAR® certified light-emitting diode (LED) bulbs concluded at the end of 2023. The program has since added: advanced power strips, nightlights, water saving kits, spray foam insulation, door sweeps, window shrink kits, air purifiers, caulk, pipe wrap, batt insulation, dehumidifiers, showerheads, and windows. Additional products are being evaluated on a regular basis.

Delivery Method and Target Market

The target market includes all residential consumers of NYSEG and RG&E. Retail storefronts embedded within the NYSEG/RG&E territories have been identified and activated to participate. Retail storefronts are chosen based on their location within the utility service territory. Final selection is based on a geotargeted drive-time analysis. The program design is intended to partner with the sales channels that represent over 95% of the market share of products and where people purchase them.

Instant discounts are reflected on the on shelves for qualified energy saving products. That reduced price automatically rings in at the register when the consumer makes their purchase. Collateral materials are placed at point of sale calling out both the discounts and the product's value proposition. Retailers provide point of sale data each month documenting the type and quantity of qualified products sold.

Coordination with other programs

The Companies use the Retail Products Program to supplement outreach to LMI/DAC customers by establishing increased focus toward retail channels that have a higher propensity to serve LMI customers – dollar stores and thrift stores. The program also works in conjunction with the LMI Distribution program by partnering with foodbanks and their associated food pantries. Details of those opportunities are further outlined in that programs section. As part of the Retail Products outreach, we also leveraged retail outreach resources to cross promote the Residential Rebate Program. All rebates are promoted at the point of sale when targeted products are purchased. Strategic placement of collateral (such as Wi-Fi Thermostat tear-pads for the Residential Rebate Program) were done during program visits.

Quality Assurance/Quality Control (QA/QC)

QA/QC activities were developed to ensure protection of the program's integrity and of customer's brand; high realization of reported savings; accuracy in reporting and invoicing; and verification that projects are being reported honestly and accurately.

QA/QC was also conducted to ensure proper execution and performance by the field staff. QA/QC measures include conducting manager ride-alongs with representatives, reviewing photos to ensure compliance, and performing random in-depth audits as well as verify enforcement of maximum quantity purchase limits. Corrective actions are taken as necessary.

Planned Program Activities

As the measure mix continues to evolve, room A/C covers, weatherstripping and outlet and switch gaskets are currently close to being implemented. We continue to evaluate non-lighting measures, especially those with insulation and air sealing benefits. Our ability to proceed with those plans will ultimately be determined by the savings yielded compared to the costs required initiate.

Home Insulation and Air Sealing Program

Program Description

The Companies introduced a Home Insulation and Air Sealing Pilot program in the 2nd quarter of 2024, whereby residential, market-rate customers were offered instant rebates for various forms of insulation (attic, wall, cellar, etc.) and whole house air sealing. Through an open contractor and aggregator network, trade allies are encouraged to apply to become an approved contractor. They assist with customer outreach solicitation and initial inspection of homeowners' unique weatherization needs, provide an estimate, and install the appropriate measures. The Pilot is intended to provide the Company with best practices to evolve and establish a permanent program to launch in 2025-2030.

The Companies utilize a full-service implementation vendor to handle all aspect of the pilot. Responsibilities include program management, administration, reporting and tracking, rebate processing & incentive fulfillment, customer care and quality assurance. They are also responsible for recruitment, training, and management of a network of certified trade alleys and aggregators. All active residential electric and natural gas customers who have their primary heating system with the Company and a central air conditioning system; or have electricity as a primary heating and cooling source are eligible for the program. All projects submitted through the pilot must have a whole house air sealing with ≥15% reduction measure and one insulation measure as a minimum for their project scope to be eligible for the incentive.

Coordination with other programs

The Company, the program's implementation contractor and NYSERDA meet monthly to collaborate on opportunities to collaborate, leverage each other's knowledge, and discuss the possibility for a complimentary program once state funded IRA incentives are released. In addition, participating contractors are provided messaging to inform customers about the Clean Heat program and the benefits of the complimentary service. Lastly, the Clean

Heat program is cross promoted in our contractor newsletter and other marketing outlets when possible. There is discussion with Clean Heat of an added "kicker" to encourage program participation, however this is likely something that will be implemented in the full launch next year.

Quality Assurance/Quality Control

All inspection applications forms go through a quality desktop control review for eligibility, completeness, and accuracy. In addition to these reviews, all projects are subject to on-site inspections that can be conducted at any time upon notification of the homeowner. These are decided on a case-by-case basis for the pilot term. Following a batch of aggregator claims that are submitted and deemed eligible, the implementation contractor will randomly select projects (5% of projects per batch) for inspection. This is a random selection across aggregators and their participating contractors. In any case, the implementation contractor may choose to exercise the option to do more inspections on an individual contractor that had the failed inspection to ensure that additional false installations are not being submitted.

Planned Program Activities

The Company is currently involved in an RFP process to secure a full-service implementation vendor for a full launch program in 2025.

Residential New Construction

Planned Program Activities

The Residential New Construction Program motivates builders of single family (market rate) to incorporate measures that exceed current building codes. The targeted savings will meet/exceed ENERGY STAR Residential New Construction performance standards based on applicable ENERGY STAR requirements for NY. Contractor Incentives will be provided to the homes that meet or exceed these standards. Measures such as heating and cooling equipment, insulation, windows, doors, water heaters, thermostats, ductwork, lighting, and appliances would be included in this program.

NYSEG/RG&E will partner with an implementation contractor (IC), local home builders and HERS raters to provide technical assistance and promote builders to adhere to ENERGY STAR Residential New Construction performance standards. The IC and HERS raters will educate and work with the builders to ensure they are meeting these standards for the newly constructed homes to leverage program incentives the 45L tax credit.

Coordination with other programs

The final program design for New Construction is still under development. However, since there is an existing new construction incentive offered for heat pumps via the Clean Heat Program, we will need to coordinate both offers to avoid double dipping on incentives.

Quality Assurance/Quality Control (QA/QC)

To ensure data accuracy, the implementation contractor will perform a desk review for eligibility and quality assurance for each project that comes through. In addition, the QC process will select and review additional sample applications before final approval of rebates. The IC will conduct a % of field QA/QC inspections of the units in participating projects at various stages of construction. Homes will be assessed during the dry-wall stage and final inspection stage.

Panel Box Upgrade Pilot

Program Description

The Panel Box Upgrade pilot provides up to $4,000 per panel box to customers for electric panel box upgrades associated to geothermal and air-source heat pump systems. It is offered to help customers overcome the technical/first cost barrier associated of homes needing a panel upgrade prior to installation of heat pumps in their home.

Delivery Method and Target Market

The Panel Box Upgrade pilot is being implemented by ICF. NYS Clean Heat registered contractors identify homes in need. They will submit all applications on behalf of the customers. The pilot was originally scheduled to run through February 2025 or until funds run out. At the time of this writing the program is still active

The program is targeted toward residential electric customers of both NYSEG and RG&E. Customer qualifications are as follows:

- Must have an active NYSEG or RG&E Electric account.
- Customer must live in a single-family home or building.
- Customer is participant in the NYS Clean Heat Program.
- Existing panel box must not be able to handle the additional load of the heat pump being installed.

Quality Assurance/Quality Control

Contractors are required to provide all incentives as an instant discount to customers. Contractors are also required to pre and post instillation photographs at the time of the application. All panel installs must be inspected by a licensed electrician, and documentation of the inspection must be provided to receive the incentive.

Planned Program Activities

Contractors have been informed via email and webinars hosted by ICF. Customers will be notified via email sent by NYSEG and RG&E.

Statewide Low and Moderate Income ("LMI") Programs

The NENY White Paper proposed the Companies should allocate at least 20% of incremental 2019-2025 energy efficiency budgets toward funding LMI programs for residential and multifamily customers. This proposal was adopted as part of the December 2020 Orders and the 20% allocation per utility is inclusive of a (statewide) 40% allocation mandate for 2019-2025 Multifamily Sector budgets.

These programs (which include Empower+ and AMEEP-Affordable MF program) are statewide collaborative efforts in partnership with NYSERDA and the other NY utilities. The efforts between the New York Utilities (Joint Utilities/" JU") and NYSERDA a joint LMI Implementation Plan ("Implementation Plan) for the statewide portfolio of energy efficiency programs and initiatives for LMI customers was filed on July 24, 2020. Since that Filing, an Annual Report was filed on April 1, 2024, which includes more details on each of those LMI programs. An updated Statewide LMI Implementation Plan will be filed October 2024 providing the most comprehensive detailed updates on our 2025 plans coordinated in parallel with the JU and NYSERDA.

LMI-1-4 Family Homes (Empower+ Program)

The Companies collaborate with NYSERDA's Empower+ program as part of a statewide joint utility effort. Additional details on planned activities and overall performance, is available in the Statewide LMI Implementation Plan.

Program Description

The LMI program conducts outreach to single family homes offering free energy assessments and efficiency upgrades (such as lighting, aerators, power strips). The portfolio of programs and offerings outlined in the Plan was designed to create a more holistic and coordinated approach to the delivery of energy efficiency programs to LMI customers and communities in New York. Consideration and design of the plan also include ways to improve the experience of and ultimate benefit for LMI customers seeking to access clean energy services; plans to reduce administrative costs and increase impact of ratepayer funding; and provide consistent and streamlined participation for service providers. NYSEG/RG&E role for this program is quite unique from every other program in our portfolio. Rather than designing and implementing our own program (with oversight of support vendors and customer etc.) we are instead tasked with supporting NYSERDA who has that existing infrastructure in place already. Our primary role is to support NYSERDA by identifying qualified customers within our own service territory and providing referrals directly into the Empower+ pipeline.

The CLM team works collaboratively with our internal Low-Income Teams. That department tracks and records customers auto enrolled or self-certified into the Low-Income Rate Reduction Program (LIRR), we also get referrals from the Office of Temporary and Disability Assistance (OTDA). Customer representatives/Advocates flagging also can manually place LIRR coding on accounts as warranted so they are included in the Data File extract. Talking points are provided to Call Center Representatives to refer customers with inquiries on energy savings or difficulty with paying their bills, to the NYSERDA EmPower+ programs to determine if they qualify. This helps to identify the subset additional eligible income customers who may not qualify for HEAP type assistance but may still qualify for EmPower+ and other NYSERDA programs. Referrals are automatically uploaded to the NYSERDA SFTP site (sftp.nyserda.ny.gov) and are retrieved by CLEAResult for processing. CLEAResult then conducts outreach efforts (via their implementation contractor) to schedule appointments and/or enroll into the Empower Program.

Quality Assurance/Quality Control (QA/QC)

NYSERDA maintains QA/QC processes and procedures to ensure data accuracy and a high-quality of work performed for its programs. This includes, performing quality checks regarding how Applications are processed, including how customer and equipment eligibility is verified and ensuring non-duplication of incentives, sampling of installed equipment in the field to verify installation quality and savings veracity; and reviewing Implementation Vendor reporting and tracking, including regular requests for performance reports, periodic requests for data needed for impact and process evaluations, and ensuring the Implementation Vendor's tracking database is well-maintained. Evaluation and Measurement (EM&V) is conducted by NYSERDA. NYSEG/RG&E pays into this EM&V study as a line item in our contract with NYSERDA. Consequently, this program does not absorb any fees or costs associated with the in-house EM&V vendor(s).

Affordable Multifamily Energy Efficiency Program (AMEEP)

Pursuant to the Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios through 2025 (case 18-M-0084), The Affordable Multifamily Energy Efficiency Program (AMEEP) statewide program launched on November 3, 2021. AMEEP offers incentives for installing energy-efficient equipment and technologies, including whole-building retrofits that address multiple building system categories (e.g., heating and cooling, insulation, lighting, etc.) The upgrades can help affordable multifamily buildings with 5+ units reduce both electricity and natural gas usage and costs while increasing operating efficiency and tenant comfort.

The Companies collaborate with NYSERDA and all the other NY utilities as part of a statewide joint effort targeted at Low Income. Additional details on planned activities and overall performance, is available in the Statewide LMI Implementation Plan.

LMI Distributions Program

Program Description

The Companies' LMI Distribution Program conducts outreach in low-income communities. Based on customer surveys conducted in collaboration with NYSERDA and other utilities via the LMI Joint Management Committee ("LMI JMC"), customers indicated they were more likely to sign up for EmPower+ when referred by a peer, with reassurances that there is no financial disadvantage to participating.

Design and Incentives

Our outreach efforts and the survey demonstrate that direct community engagement is a very effective way to engage with these communities, as they build community awareness and allow customers to ask questions about available programs. The NYSEG/RG&E energy efficiency team also collaborates actively with our Customer Advocates[105] to target joint efforts in the community as well. To that end, we seek opportunities to provide education and distribute efficient products to low-income customers. Targeted venues include local foodbanks, and various community events where it's likely that low-income consumers would be present (most notably outreach to neighborhoods deemed DACs by the Climate Justice Working Group criteria).

Delivery Method and Target Market

Products are delivered in person at foodbanks, and other special events. This outreach not only provides our most vulnerable customers access to immediate energy savings and education but also serves as a marketing and outreach tool to cross promote Empower+ and solicit enrollments in our statewide comprehensive program.

Planned Program Activities

Throughout 2025 we plan to continue cross promotion to sign up for Empower+ as part of our engagement with our community outreach.

Quality Assurance/Quality Control

Energy savings is calculated by using the formulas and factors/parameters found in the Technical Resource Manual (TRM).

School Kit Program

Program Description

The school kit program provides 5th grade students and parents within NYSEG and RG&E service territories with an award-winning education program. The program is an excellent delivery method for targeting residential NYSEG/RG&E customers to develop awareness, interest, and household participation in additional programs encompassed in NYSEG/RG&E's energy efficiency and demand response portfolio.

Design and Incentives

The program offers a variety of materials that serve to produce a successful program experience for the teachers, students, and their families. The program team provides free

[105] Customer Advocates are NYSEG/RG&E employees who work proactively in their communities to serve customers in need to identify needs and provide available resources.

energy saving measures (with focus on small scale DIY air sealing). Also included in the kits are customized materials that captivate participants behavioral change-based educational components. Materials are engaging and organized, reinforcing measure installation and program completion. Step-by-step directions are provided for the teacher to ensure program milestones are achieved within an appropriate timeline.

Delivery Method and Target Market

The target market consists of Title 1 Schools and/or schools located within a DAC. The basic principles of Title 1 states that schools with large concentrations of low-income students will receive supplemental funds to assist in meeting student's educational goals. Low-income students are determined by the number of students enrolled in the free and reduced lunch program. Census Tracts will also be established by any school located within NYSEG/RG&E territory and within a DAC community. The teacher opts their classroom into the program. We then ship materials for each eligible teacher and student the teacher identified in their registration.

Quality Assurance/Quality Control

Energy savings is calculated by using the formulas and factors/parameters found in the Technical Resource Manual (TRM).

Planned Program Activities

In 2025 we plan to continue cross promotion to sign up for Empower+ as part of our engagement with our school's outreach.

- Demand Response: Smart savings reward offering residential and small business customers with smart thermostat discounts, commercial system relief program to reduce peak consumption

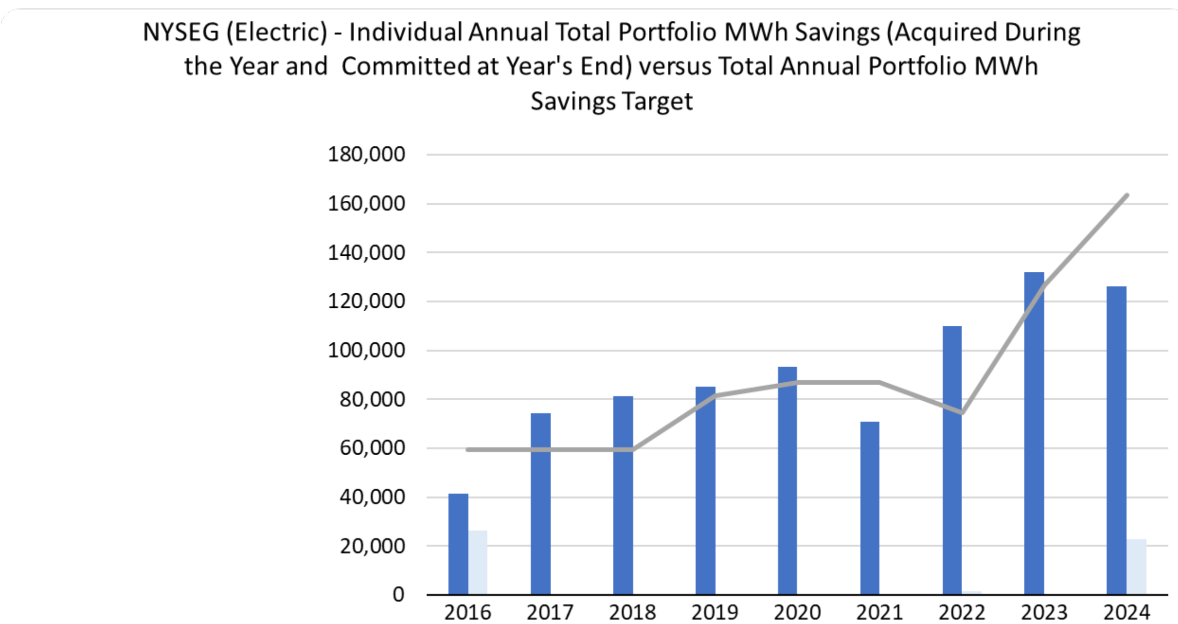
Describe the future implementation that is planned to be deployed by June 30, 2030, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2030 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation; Described where and how plans for topic-related work and investments *affect the CGPP; Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.*

As stated above the collective needs of stakeholders via the July 2023 orders the Companies to shift away from non-strategic measures over to Strategic measures. This eliminates measures that have historically delivered the majority of electric savings. In its place our focus is on holistic savings focused primarily on building shell (making homes and businesses heat pump ready) and the eventual installation of heat pumps. Savings for MWh only be reduced in future years. In its place we proposed tracking success via net MMBTU reductions.

AMI-enabled data analytics could help to refine specialized outreach to each consumers' unique needs and interests. For example, the higher usage customers located in low-income areas could be targeted for weatherization or be offered some of our low-income specific program offerings. Detail on high electric usage by the days and hours may give us increased visibility to the ideal candidates to transition to a heat pump program.

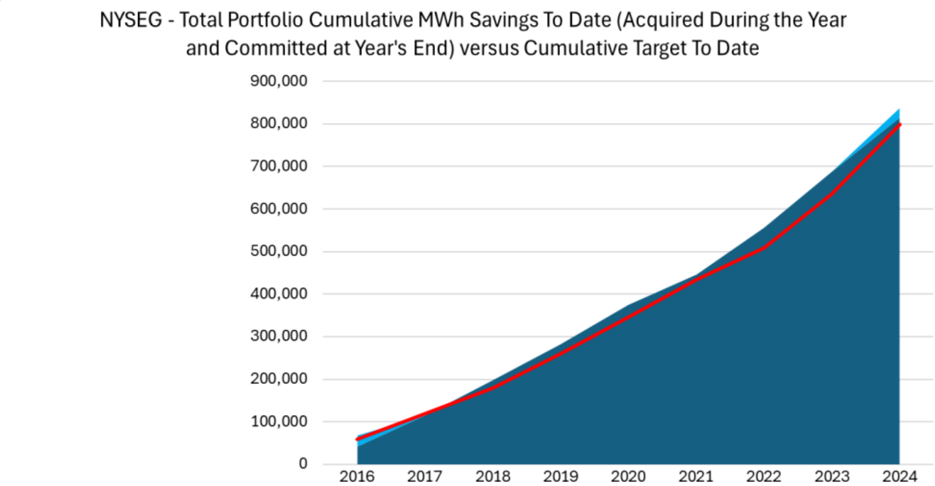
NYSEG and RG&E energy efficiency targets through 2024 are included below.

EXHIBIT 2.7-1: NYSEG - YoY MWh SAVINGS



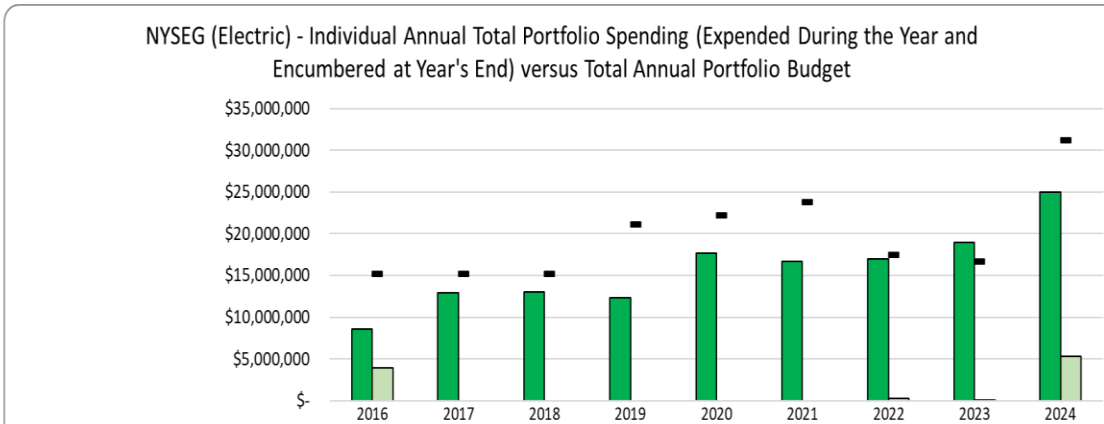
	2016	2017	2018	2019	2020	2021	2022	2023	2024
Sum of Acquired MWh This Year	41,433	74,147	81,435	85,056	93,327	70,840	109,871	132,115	126,181
MWh Savings Currently Committed	26,242	0	0	0	0	0	1,405	178	22,837
Sum of Planned MWh This Year	59,508	59,508	59,508	81,525	87,032	86,793	74,299	126,700	163,419

EXHIBIT 2.7-2: NYSEG CUMULATIVE MWh SAVINGS



	2016	2017	2018	2019	2020	2021	2022	2023	2024
MWh Savings Committed at Year's End	26,242	0	0	0	0	0	0	178	22,837
Sum of Acquired MWh to date	41,433	115,581	197,016	282,072	375,398	446,238	556,109	688,224	814,405
Sum of Planned MWh to date	59,508	119,015	178,523	260,048	347,080	433,872	508,171	634,871	798,290

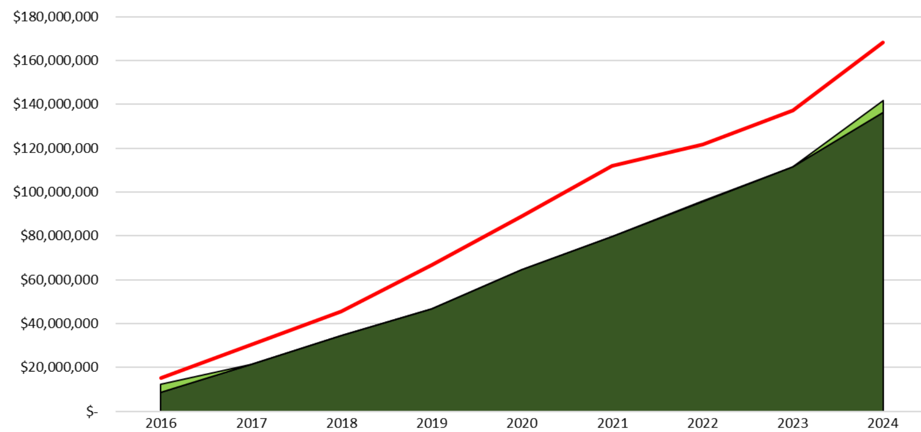
EXHIBIT 2.7-3: NYSEG EXPENDITURES



	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Portfolio Expenditures this Year	$8,535,408	$12,955,949	$13,008,559	$12,284,049	$17,643,891	$16,628,879	$16,926,776	$18,913,561	$24,968,529
Total Portfolio Funds Currently Encumbered	$3,910,945	$-	$-	$-	$-	$0	$273,209	$92,699	$5,358,393
Sum of Current Year Budget	$15,193,605	$15,205,639	$15,234,692	$21,150,874	$22,179,733	$23,778,302	$17,472,611	$16,637,358	$31,211,093

EXHIBIT 2.7-4: NYSEG CUMULATIVE EXPENDITURES

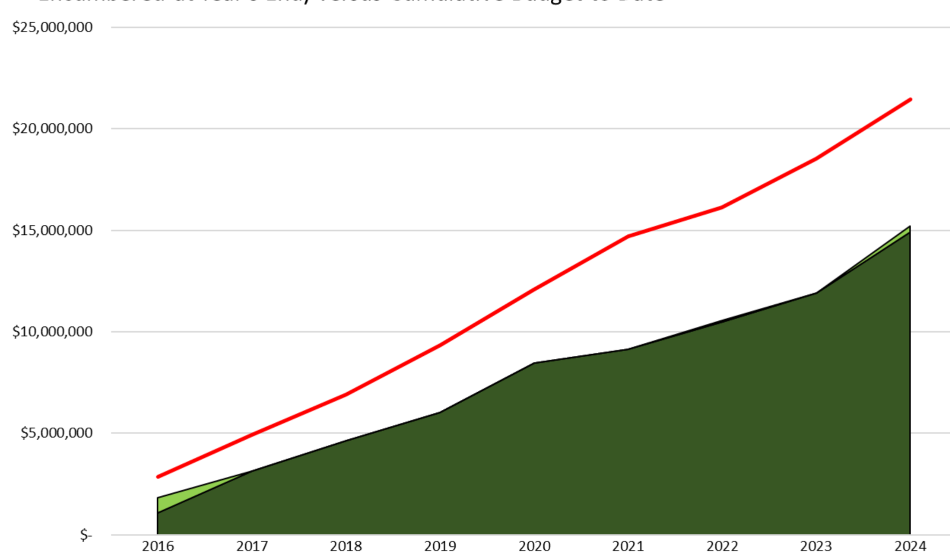
NYSEG (Electric) - Total Portfolio Cumulative Spending to Date (Expended During the Year and Encumbered at Year's End) versus Budget to Date



	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Portfolio Funds Encumbered at Year's End	$3,910,945	$-	$-	$-	$-	$0	$273,209	$92,699	$5,358,393
Total Portfolio Expenditures to Date	$8,535,408	$21,491,357	$34,499,916	$46,783,965	$64,427,856	$79,902,625	$95,639,570	$111,400,067	$136,368,596
Total Portfolio Budget to Date	$15,193,605	$30,399,244	$45,633,936	$66,784,810	$88,964,542	$112,079,877	$121,615,022	$137,063,074	$168,274,166

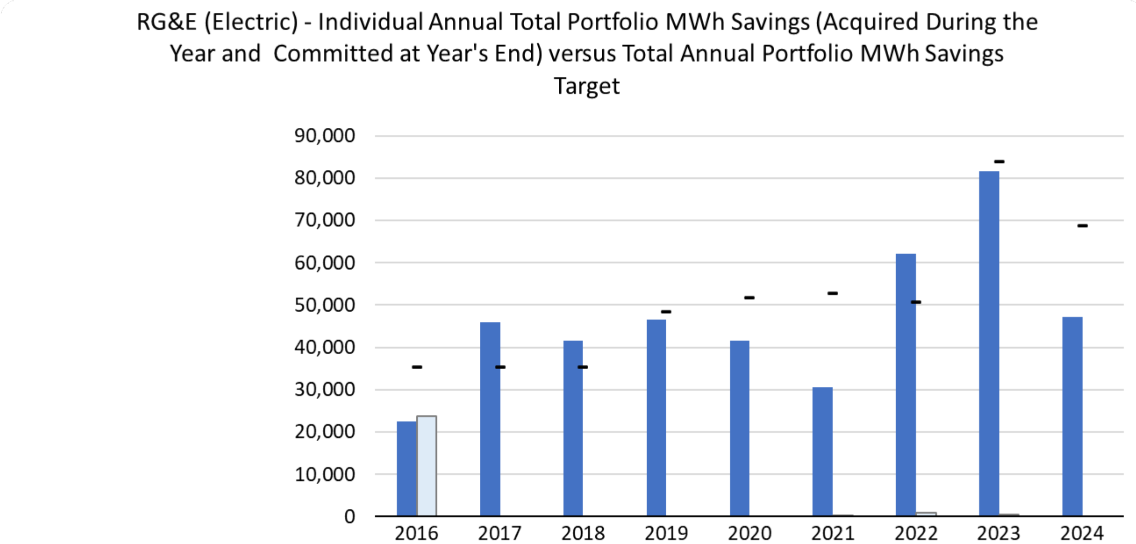
EXHIBIT 2.7-5: NYSEG GAS CUMULATIVE EXPENDITURES

NYSEG (Gas) - Total Portfolio Cumulative Spending to Date (Expended During the Year and Encumbered at Year's End) versus Cumulative Budget to Date



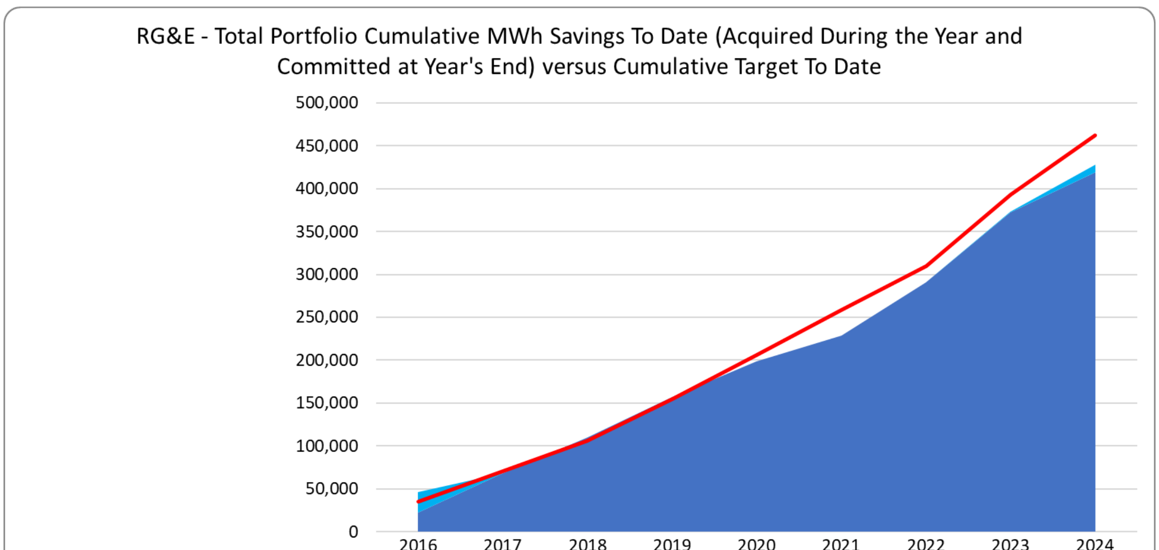
	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Portfolio Funds Encumbered at Year's End	$755,497	$-	$-	$-	$-	$-	$97,671	$23,917	$298,321
Total Portfolio Expenditures to Date	$1,076,761	$3,132,526	$4,639,626	$6,016,527	$8,465,142	$9,139,080	$10,476,820	$11,891,333	$14,893,450
Total Portfolio Budget to Date	$2,864,023	$4,902,240	$6,920,455	$9,351,604	$12,077,457	$14,702,449	$16,134,296	$18,518,173	$21,451,401

EXHIBIT 2.7-6: RG&E -YoY MWh SAVINGS



	2016	2017	2018	2019	2020	2021	2022	2023	2024
Sum of Acquired MWh This Year	22,477	46,020	41,541	46,542	41,625	30,546	62,033	81,545	47,207
MWh Savings Currently Committed	23,752	0	0	0	0	97	886	464	
Sum of Planned MWh This Year	35,307	35,307	35,307	48,413	51,691	52,774	50,674	83,900	68,833

EXHIBIT 2.7-7: RG&E CUMULATIVE MWh SAVINGS



	2016	2017	2018	2019	2020	2021	2022	2023	2024
MWh Savings Committed ay Year's End	23,752	0	0	0	0	97	144	464	8,663
Sum of Acquired MWh to date	22,477	68,496	110,037	156,579	198,204	228,750	290,783	372,328	419,536
Sum of Planned MWh to date	35,307	70,613	105,920	154,333	206,025	258,798	309,472	393,372	462,205

EXHIBIT 2.7-8: RG&E EXPENDITURES

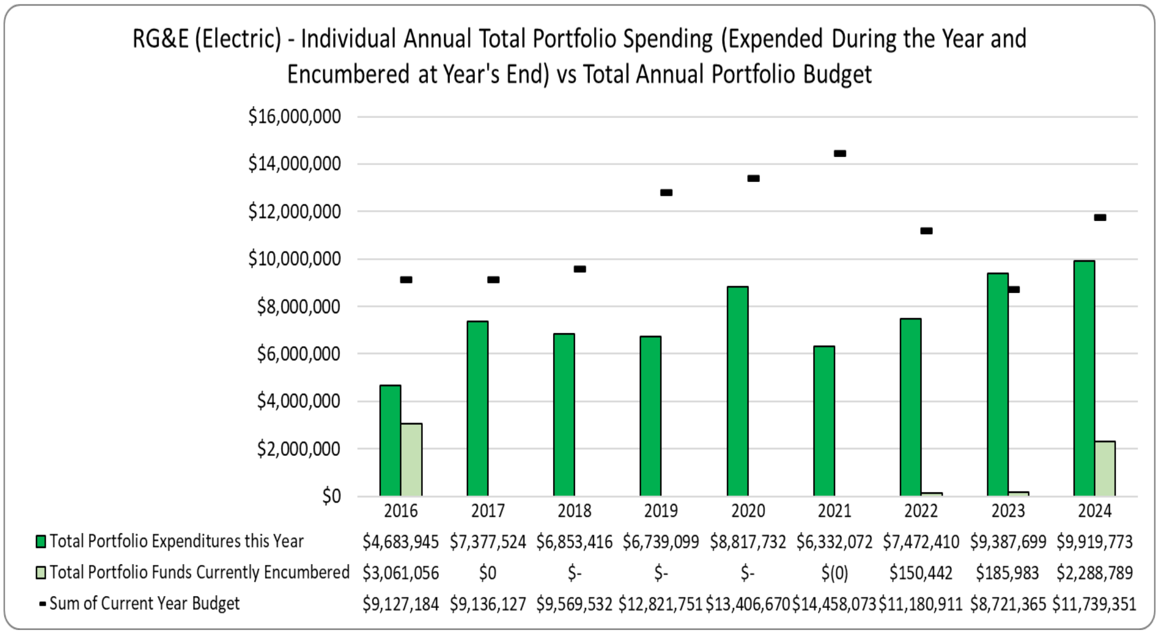
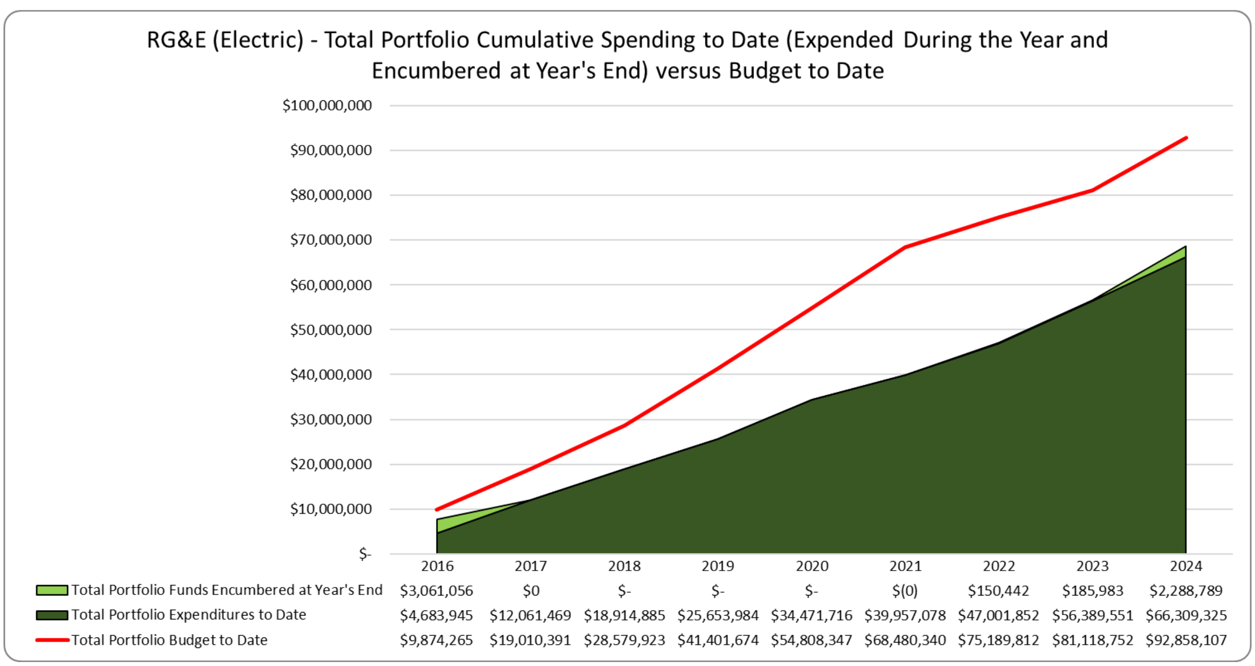


EXHIBIT 2.7-9: RG&E CUMULATIVE EXPENDITURES



In January 2024, the Companies submitted a revised EE/BE Proposal representing a total 5-year investment of approximately $400 million ($279 million from NYSEG and $121 million from RG&E) for 2026-2030, with most funding allocated to the Clean Heat Program as well as a Residential Insulation and Air Sealing program.[106] Moreover our proposal demonstrated a significant shift away from traditional measures eliminating the promotion of lighting, home energy reports, appliance rebates, and gas combustion equipment.

To support the development of the proposed non-LMI energy efficiency portfolios for Upstate New York, a technical conference was held in Albany on February 8, 2024. This conference provided an opportunity for stakeholders to review and discuss the proposed portfolios. A public comment and stakeholder feedback period followed the event.

On May 15, 2025, the PSC issued an order approving the proposals with certain modifications. In accordance with the ordering clauses related to the non-LMI portfolio, the Companies are required to submit preliminary revised plans addressing those modifications.

The Companies are in the process of developing a revised preliminary 2026 – 2030 EE/BE Plan to be filed July 15, 2025. The below sets of data reflect the most current draft plans which will be adjusted in collaboration with DPS and various stakeholders over the remainder of 2025. The amounts reflected in Exhibits 2.7-10 and 2.7-11 are preliminary and subject to change.

[106] NE:NY Proceeding, EE/BE Order, Appendix, p. 100.

EXHIBIT 2.7-10: NYSEG-TOTAL PROPOSED PORTFOLIO ANNUAL ACQUIRED SAVINGS - Non-LMI

	2026	2027	2028	2029	2030	2026-2030	Annual Average
Electric							
MWh	55,387	61,097	67,396	74,345	82,010	340,235	68,047
MWh Usage Resulting from Heat Pump Installations	(26,730)	(30,472)	(34,739)	(38,213)	(40,123)	(170,277)	(34,055)
MMBtu	281,371	320,763	365,670	402,237	422,349	1,792,390	358,478
Estimated distribution of MMBtu by displaced fuel:							
Gas	98,480	112,267	127,985	140,783	147,822	627,337	125,467
Oil	123,803	141,136	160,895	176,984	185,834	788,652	157,730
Electric	36,578	41,699	47,537	52,291	54,905	233,011	46,602
Other	22,510	25,661	29,254	32,179	33,788	143,391	28,678
Gas							
MWh						-	
MWh Usage Resulting from Heat Pump Installations						-	
MMBtu	181,279	189,496	198,134	207,219	216,781	992,909	198,582
Estimated distribution of MMBtu by displaced fuel:							
Gas						-	
Oil						-	
Electric						-	
Other						-	
Combined E&G							
MWh	55,387	61,097	67,396	74,345	82,010	340,235	68,047
MWh Usage Resulting from Heat Pump Installations	(26,730)	(30,472)	(34,739)	(38,213)	(40,123)	(170,277)	(34,055)
MMBtu	462,650	510,259	563,804	609,456	639,130	2,785,299	557,060
Estimated distribution of MMBtu by displaced fuel:							
Gas	98,480	112,267	127,985	140,783	147,822	627,337	125,467
Oil	123,803	141,136	160,895	176,984	185,834	788,652	157,730
Electric	36,578	41,699	47,537	52,291	54,905	233,011	46,602
Other	22,510	25,661	29,254	32,179	33,788	143,391	28,678

Total Combined E&G MMBtu Equivalent (MMBtu[e])	560,426	614,750	675,232	732,740	782,047	3,365,195	673,039

EXHIBIT 2.7-11: RG&E TOTAL PROPOSED PORTFOLIO ANNUAL ACQUIRED SAVINGS - Non-LMI

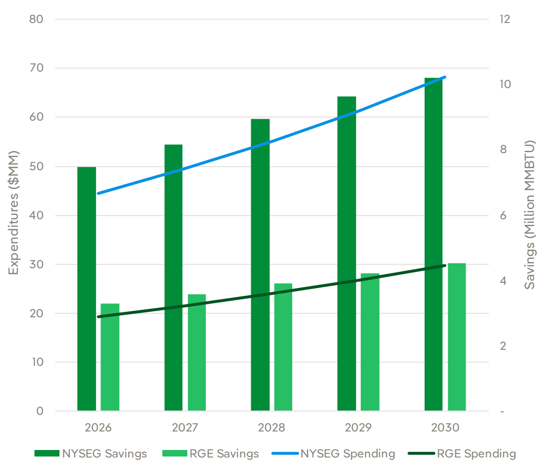
	2026	2027	2028	2029	2030	2026-2030	Annual Average
Electric							
MWh	25,254	27,385	29,697	32,204	34,922	149,462	29,892
MWh Usage Resulting from Heat Pump Installations	(5,704)	(6,503)	(7,413)	(8,155)	(8,562)	(36,337)	(7,267)
MMBtu	60,044	68,450	78,034	85,837	90,129	382,494	76,499
Estimated distribution of MMBtu by displaced fuel:							
Gas	21,015	23,958	27,312	30,043	31,545	133,873	
Oil	26,419	30,118	34,335	37,768	39,657	168,297	
Electric	7,806	8,899	10,144	11,159	11,717	49,724	
Other	4,804	5,476	6,243	6,867	7,210	30,600	
Gas							
MWh						-	
MWh Usage Resulting from Heat Pump Installations						-	
MMBtu	131,598	140,708	150,488	160,993	172,281	756,069	151,214
Estimated distribution of MMBtu by displaced fuel:							
Gas						-	
Oil						-	
Electric						-	
Other						-	
Combined E&G							
MWh	25,254	27,385	29,697	32,204	34,922	149,462	29,892
MWh Usage Resulting from Heat Pump Installations	(5,704)	(6,503)	(7,413)	(8,155)	(8,562)	(36,337)	(7,267)
MMBtu	191,642	209,158	228,522	246,830	262,410	1,138,563	227,713
Estimated distribution of MMBtu by displaced fuel:							
Gas	21,015	23,958	27,312	30,043	31,545	133,873	26,775
Oil	26,419	30,118	34,335	37,768	39,657	168,297	33,659
Electric	7,806	8,899	10,144	11,159	11,717	49,724	9,945
Other	4,804	5,476	6,243	6,867	7,210	30,600	6,120
Total Combined E&G MMBtu Equivalent ($MMBtu^e$)	258,346	280,409	304,554	328,886	352,351	1,524,547	304,909

EXHIBIT 2.7-12: PROPOSED 2026-2030 EXPENDITURES & TARGETED SAVINGS

The tables below provide the proposed 2026-2030 expenditures (not including internal labor of $16M over 5 years for the Companies) and targeted savings.

Proposal Summary, Metrics, Targets, Budgets

YoY Proposed Savings and Expenditures



Budget and Key Outcomes

- $400M investment over 5 years
  - $279M NYSEG
  - $121M RG&E
- 64M Lifetime MMBTU savings planned

Proposed Metrics

- Switch to lifetime/per MMBTU
- 85% of $ on Strategic measures
- % of investments in DACs (NYSEG/ RG&E contribution to statewide goal of at least 35% benefits to DACs (goal of 40%))
- Homes electrified, weatherized
- Local community events, activities

Coordination on IRA funding

- Continued Referrals of LMI programs
- Tax credits and other info on all collateral

Proposed Shift in YoY Funding

- Forecasted gradual increase YoY
- Flexibility is key due to changing market conditions
- 20% +/- year over year

6

EXHIBIT 2.7-13: ENERGY EFFICIENCY ROADMAP

Capability	Achievements (2023-2025)	Short-Term Initiatives (2026-2027)	Long-Term Initiatives (2028-20230)
Achieve NE:NY MWh Savings Targets	• NYSEG: 871,946 • RG&E: 442,765	• 2024 • NYSEG: 138,991 • RG&E: 53,973 • 2025 (estimated) • NYSEG: 34,777 • RG&E: 14,817	NYSEG: 170,000 RG&E: 113,000
Energy Efficiency Customer Offerings	• Launched statewide NY Clean Heat program and LMI Residential and Multifamily programs in 2020 • Economic Development Heat Pump Program launched in 2021 • Demand response reward offerings <u>Commercial/Industrial</u>: • Incorporated Commercial Comprehensive New Construction into current Non-Residential program for ease of customer access • Added Small Business Customer Choice program as a parallel path for small business customers not needing direct install <u>Residential</u>: • Retail Products instant rebate added to portfolio in 2022. • Retail Product LMI program added in 2022. • Behavior program added in 2021 • Low Income Distributions program added in 2022.	• Continuation of program expansion to meet NENY goals • Expansion of commercial programs to reach more customers • Heat Pump and LMI programs as directed by Jan. 2020 EE Order / Joint Utilities Statewide Plan • Staff Interim Review of EE programs, budgets, targets	Transition EE portfolio to promoting Strategic Measures with focus on insulation, air sealing, building shell. Focus is also on building electrification. So metric targets are envisioned to be tracked at a NET MMBTU basis. Targeted promotions for DAC customers.
Customer Access to Energy Usage	• Energy Manager launched	• Statewide AMI-enabled data analysis and programs	• Ongoing development and integration with Energy Manager platform
Customer Segmentation for Targeted Offerings	• Customer Selection for Behavioral Segmentations Program • Customer segmentation for LMI offerings	• Continued customer segmentation for LMI, heat pump, and future offerings	DAC outreach/programs

<u>Integrated Implementation Timeline</u>: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2030. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

See the exhibit above for the Companies' Energy Efficiency Roadmap.

Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E have identified three risks related to performance of our EE efforts, and have taken measures to mitigate each risk, as shown in Exhibit 2.7-15

EXHIBIT 2.7-14: ENERGY EFFICIENCY RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Delivering Customer Value:** Customer value will also be driven by the products and services offered by third parties using the NYSEG/RG&E platform.	• Communicate value and promote customer adoption of products and services • Advocate REV policies that align with customer value
2. **Execution:** Ability to collaborate with internal and external stakeholders to integrate energy efficiency.	• Integrate energy efficiency into Integrated Planning NWA processes
3. **Timing:** Ability to engage vendors, timely award contracts, and ramp up new programs, which are imperative to meeting annual targets.	• Engage with vendors early in the process • Work closely with procurement team • Develop RFP schedules • Potentially extend existing contracts with vendors, if necessary
4. **Transition from EE lighting to new and innovative EE products**	• Identify new measures to replace savings gaps as result of phase out of lighting. • Assess forward looking analysis on revised costs per savings as the new and innovative measures are included. • Level set metrics away from MWh and over to lifetime MMBTU to further align with revised NENY vision.

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category's needs will be met over time; Describe and explain the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as *feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.*

When it comes to determining the final plans specific to energy efficiency and aligning those with the goals and needs of each stakeholder, The Companies have followed the requirements of the rate case and joint proposal process. Stakeholders are provided the opportunity to present their goals and needs which are incorporated into the regulatory review. Stakeholders have opportunities to review proposed plans by The Companies which is also incorporated into the final Orders and/or joint proposals. It is ultimately up to the Commission to determine what the final ordering clauses are and what The Companies are obligated to implement.

The most recent example, being the process associated with the development of our 2026-2030 Proposal. Stakeholders had an opportunity to review all companies' draft proposals and provide feedback. An in person technical conference was held with open Q&A on February 8, 2024. That was followed up by additional feedback and comments period in Q1 of 2024 submitted to the DPS Staff.

To that end, and once we have been issued our orders, the Companies continue to work with and collaborate and have been active participants in stakeholder engagement activities, including:

- Weekly Joint Utilities working group meetings The New York State Joint Utility Committee, also known as the Joint Utilities of New York, plays a crucial role in advancing the state's clean energy and efficiency goals. This committee is comprised of several major utility companies, including Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation, National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.
- The primary purpose of the Joint Utilities is to collaborate on initiatives that support New York's clean energy transition. This includes working towards the ambitious targets set by the CLCPA, which aims for net-zero greenhouse gas emissions in the coming decades. The committee focuses on system efficiency, reliability, resilience, market animation, utility business models, customer empowerment, and greenhouse gas emissions reduction.
- Additionally, the Joint Utilities engage with stakeholders to better understand shared needs and objectives, particularly in relation to distribution-connected, small-scale

energy resources.

- Weekly meetings with the Joint Utilities, New York DPS Staff, and NYSERDA;
- Collaboration with NYSERDA on program development, including structures for Clean Heat program as well as heat pump pilot programs
- Weekly JMC participation with statewide low-income initiatives including Empower, Affordable Multi-Family Program, LMI General JMC, LMI Evaluation, Management and Verification ("EMV") sub-committee and the LMI marketing subcommittee.
- Engagement with DPS Staff on implementing aggressive EE targets and reaching statewide goals; and
- LMI stakeholder forums from 2020-2024, as directed by the January 2020 EE Order;
- NY Clean Heat PCIP webinars

The Companies will also participate with the Joint Utilities and NYSERDA (advised by Staff) in Joint Management Committees for the heat pump and LMI efforts going forward, including holding a minimum of two stakeholder sessions annually to review the Statewide LMI programs.[107]

The Joint Utilities also filed comments in March 2023, in response to the Staff Energy Efficiency/Building Electrification Report. In addition to responding to Staff's questions, the Joint Utilities addressed numerous topics including, the future of program targets and budgets, program timelines, and the statewide LMI framework.

[107] Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025 (issued and effective January 16, 2020), Ordering Clause 11.

Additional Detail

Energy Efficiency integration with a focus on innovative market enabling tools and approaches is an essential utility function that needs to be thoroughly addressed within the five-year planning horizon of the DSIP Update filing. It also affects the CGPP integrated system analysis, as energy efficiency efforts act as load modifiers in distribution planning. This load impact is then incorporated into the CGPP as part of its analysis for local transmission and distribution projects.

DPS Staff recommends that the utilities should provide the information specified below to show how their joint and individual efforts are fully integrating current and expanded energy efficiency efforts into their system planning. DPS Staff further recommends that the utilities should also describe how new tools and approaches are being used to support the growth of a more dynamic market of service providers that deliver energy efficiency at a reduced cost by leveraging private capital and financing to deliver greater customer value while optimizing the grid value of these services. Each utility has evolved its Efficiency Transition Implementation Plans (ETIPs) into System Energy Efficiency Plans (SEEPs) that describe the entirety of the utility's expanded reliance on and use of cost-effective energy efficiency to support their distribution system and customer needs. ETIPs / SEEPs will continue to be filed separately in accordance with DPS Staff issued ETIP / SEEP Content Guidance, but DPS Staff recommends that the DSIP must incorporate and plan for the integration and reliance on these expanded energy efficiency resources and should include a link to the most recent ETIP/SEEP filing.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to energy efficiency:

Our SEEPs support the vision for potential future energy efficiency services, which are flexible and support REV principles. Most notably those promoting system reliability and resiliency, market animation, leveraging ratepayer contributions, and the reduction of carbon emissions. The two most recent SEEPs were filed on October 1, 2023, and October 1, 2024, describing the Companies' EE programs.[108]

1. *The resources and capabilities used for integrating EE within system and utility business planning.*

Please see Current Progress and Future Implementation and Planning for more details.

[108] The Companies' most recent System Energy Efficiency Plan is available at the following link https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bF234C63A-0C1A-4E3F-97D2-EF770BBF7.

2. *The locations and amounts of current energy and peak load reductions attributable to energy efficiency and how the utility determines these.*

We do not currently have an automated way to track the location of savings from energy efficiency programs, other than for identified NWA opportunities. NYSEG and RG&E estimate the location and amounts of anticipated energy and peak load reductions when they are associated with an NWA. These are based on customer-specific assessments and we rely on them when defining the NWA requirements. The Annual DR report provides load reductions attributable to demand response programs. Energy Savings resulting from Energy Efficiency programs is tracked at the portfolio level (rather than locational) and reported on the Clean Energy Dashboard, a new resource since the 2018 DSIP. [109] The Clean Energy Dashboard was created from the previously-used EE Scorecards, and provides more accessible information to customers and stakeholders.

3. *A high-level description of how the utility's accomplishments and plans are aligned with New York State climate and energy policies and incorporate innovative approaches for accelerating progress to ultimately align with the CLCPA.*

On an annual basis we develop an updated System Energy Efficiency Plan (SEEP) which aligns with approved funding in our rate case. Adjustments are made as we compare the dollars approved to the targeted expenditures.

4. *Summary information on energy efficiency programs offered by the utility, with direction to annual filings for more detailed information on energy efficiency programs.*

Please see Current Progress section above for detailed information on all Active EE programs.

[109] The Clean Energy Dashboard provides customers with program activity snapshots for each New York utility and NYSERDA. Utilities submit information online to the DMM system, and that information is rolled up statewide onto the Clean Energy Dashboard, which is administered by NYSERDA. The dashboard aggregates information, such as CO2 emissions reductions, renewable energy capacity and generation, energy savings, and peak demand reductions by utility and NYSERDA. The dashboard is available here. Clean Energy Dashboard - NYSERDA

5. *Describe how the utility is coordinating and partnering with NYSERDA's related ongoing statewide efforts to facilitate energy efficiency market development and growth.*

The Energy Efficiency team has been involved in weekly meetings with NYSERDA, Joint Utilities, and DPS Staff on EE efforts, as well as development of statewide structures for heat pump and LMI programs. This includes involvement in the Joint Management Committees for heat pumps and LMI. The EE team has also developed a memorandum of understanding ("MOU") with NYSERDA to transfer funds to NYSERDA to expand the footprint of customers they currently serve under the Empower Program for low income customers (basically NYSEG and RG&E are providing funding to expand the number of customers they can serve). The EE team has also been working with a consultant to develop co-marketing with NYSERDA for heat pump marketing campaigns. EE personnel have met with NYSERDA to coordinate efforts to serve the Agricultural sector including ongoing communications between the Companies' C&I program implementer and NYSERDA contractors. As well, the Companies continue to work with NYSERDA on heat pump related pilots in their service terriorty.

The Companies' EE programs worked closely with and co-funded a project with NYSERDA on a large chiller project at RED-Rochester, LLC in RG&E service territory. RED Rochester is a privately-owned generation facility that produces electricity, steam, and chilled water for more than 100 companies operating at the Eastman Business Park in Rochester.

2.8 Data Sharing

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2023 DSIP Update filing.

Data is at the heart of all system processes and technologies under development, with AMI providing grid edge data on customer usage rates, grid automation and management providing data on grid operations and DERs along the grid, while grid planners use this real-time data to develop long-term plans. This initiative refers to the platforms that turn "big data" into actionable insights for customers, DER developers, and the Companies.

The Companies' data and analytics initiative capabilities include:

1. External Data-Sharing Platform – IEDR; and
2. GMEP

These capabilities are described in more detail below.

1. External Data-Sharing Platform – IEDR

New York is transforming its electricity system into one that is cleaner, more resilient, and affordable through changes in energy policy. Adequate access to useful energy and energy related data is required to achieve this transformation. The IEDR platform is intended to be a statewide, centralized platform that will allow third parties and customers access to useful energy data and information from New York's electric, gas, and steam utilities. The IEDR platform is intended to foster innovative clean energy business models to benefit customers and support CLCPA goals through support of DER integration. System data and information provided may include customer usage data from AMI, aggregated load data, data on NWAs, hosting capacity maps, identification of beneficial locations to DER developers, asset data information, and customer billing data.

On February 11, 2021, the New York PSC issued the IEDR Order[110] based on DPS staff recommendations,[111] where the Order directed the development of an IEDR to securely collect, integrate, and provide broad and appropriate access to large and diverse sets of valuable energy and energy-related information on one statewide data platform. The IEDR

[110] Case 20-M-0082, Order Implementing an Integrated Energy Data Resource (issued February 11, 2021), p. 39.

[111] Case 20-M-0082, Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data, Department of Public Service Staff Whitepaper Recommendation to Implement an Integrated Energy Data Resource, May 29, 2020.

Order designated NYSERDA as the IEDR Program Sponsor responsible for defining, initiating, overseeing, and facilitating the IEDR Program on behalf of New York.

The IEDR Order articulated the foundational principles for developing the IEDR throughout its life cycle and stated that the policy of obtaining the best overall value for NYS would guide the IEDR. NYSERDA, as the Program Sponsor, established a program-guiding process—based on the three commitments below—to deliver the best overall value:

1. Conducting effective and extensive collaboration with and among stakeholders, including the state's utilities, to identify use cases of value to them. (A use case represents access to data, combinations of data, analysis, or other functions that create value for a specific type of user by supporting a specific identified use or outcome.)
2. Procuring the services of individuals and organizations with the necessary expertise and experience in developing, implementing, and operating a data platform of similar scale and scope.
3. Establishing unambiguous performance requirements, including firm schedules and milestones.

The IEDR Order established the regulatory expectation that the IEDR will enable approximately 50 use cases throughout two phases of development, with specific deadlines for achieving minimum performance capabilities:

- **Phase 1:** The initial IEDR implementation was required to enable at least five of the highest priority use cases with an expectation that 10 or more could be achieved and was scheduled to be completed 24 to 30 months after the Program Manager's work commenced.
- **Phase 2:** The initial IEDR is anticipated to expand and enhance approximately 40 additional use cases, building on the successful implementation and operation of Phase 1. Phase 2 is scheduled to be completed 30 to 36 months after the completion of Phase 1 (October 1, 2026 – April 1, 2027).

Additionally, in April 2021 the PSC issued an order, Adopting a Data Access Framework ("DAF") and Establishing Further Process (the "DAF Order[112]"), w hereby t he C ommissionn established a uniform and comprehensive Data Access Framework to govern the means and

[112] Case 20-M-0082, In the Matter of the Strategic Use of Energy Related Data, Order Adopting a Data Access Framework and Establishing Further Process, April 15, 2021.

methods for accessing and protecting all energy-related information.[113] On October 13, 2023, the Commission issued the Order Addressing Integrated Energy Data Resource Matters (the October 2023 Order), whereby the Commission clarified that the IEDR Platform is a "data custodian" and stated that "[t]he IEDR is such a centralized data warehouse that will function as a data custodian for the purposes of managing the energy-related data received from various sources, including from the Joint Utilities (JU)."[4] The October 2023 Order further required the JU to transfer Customer Data Sets to the IEDR Administrator[5] (the IEDR Development Team) without customer consent, as such a transfer is an exchange of customer data between data custodians. The October 2023 Order, in relevant parts, stated that "[a]s a data custodian, the IEDR will be governed by the DAF, which establishes the means and methods for ESEs to access Customer Data Sets and other energy-related information from the IEDR platform, while ensuring that such information is properly protected from unauthorized disclosures." Accordingly, all aspects of the IEDR comply and will continue to comply with the framework and requirements that the Commission established for the DAF.

On January 19, 2024, the PSC issued their Order Approving Integrated Energy Data Resource Phase 2 Budgets (the January 2024 Order)[114]. The January 2024, approved funding for Phase 2 of the IEDR Program, which officially began on April 1, 2024. Phase 2 funding will support the established regulatory expectations that the IEDR will enable approximately 50 use cases by the end of Phase 2, by building on the accomplishments of Phase 1, and deploying approximately 40 additional use cases.

The Utilities submitted their first round of test data on June 17, 2022, to help the IEDR Program Team build out the platform. The Joint Utilities sent a second round of Initial Public Version ("IPV") Test Data for Hosting Capacity Maps and DER use cases in November/December 2022. This will assist the IEDR Development Team in understanding the structure and format of utility data, which will aid implementation of the IPV use cases and overall development of the IEDR platform.

On March 31, 2023, the IPV was released by NYSERDA, addressing three priority use cases:

- **Consolidated Hosting Capacity Maps:** This use case supports DER developers, DER owners and/or utilities to view all hosting capacity maps for the entire state in one

[113] Case 20-M-0082, Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data, Order Addressing Integrated Energy Data Resource Matters, October 13, 2023.
[114] Case 20-M-0082, Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data, Order Approving Integrated Energy Data Resource Phase 2 Budgets, January 19, 2024.

map view with consistent data, so that users can site new DERs and monitor the state of DER development in New York accurately.

- **Installed DERs:** This use case supports Energy Service Entities (ESE) and/or government staff members who want to view all installed DERs that utilities have data on (e.g., the SIR inventory), so they can site new DERs or monitor the state of DER development in New York. This use case also provides access to the necessary information pertaining to installed DERs including attributes, location, and status in a consistent format across the entire utility service territories.
- **Planned DERs**: This use case supports Energy Service Entities (ESEs) who want to view and monitor all planned DERs that utilities have data on (e.g., the SIR inventory), so they can site new DERs or monitor the state of DER development in New York.

On March 27, 2024, additional use cases were released in a Minimum Viable Product (MVP) by NYSERDA:

- **Find and Filter Rate Options Across NYS IOU Utilities:** This use case will allow Energy Service Entities (ESE) or government staff members to view a list of rates/tariffs across New York State utilities filterable by key criteria (e.g., rate name, rate type, location, etc.), in order to quickly navigate to pertinent rate information.
- **Access to Basic Rate Data and Tariff Book for Individual Rate:** This use case will allow users to see all information about a single rate in one place; enabling those estimating energy customer bills to access relevant data more easily and precisely than they are currently able to. Specific features of this use case include: making rate parameters that change slowly (rate periods, Holidays, Seasons, minimum and other fixed charges, and baseline allowances aka tiered block rates) available in structured format, and facilitating easier navigation to the section of the tariff book where rate parameters for a given rate can be found (which includes easier navigation to both the most recent version of the tariff book itself and historical versions of the tariff book).
- **Efficient and Effective Access to Existing Customer Billing Data:** For the MVP release, the use case "Efficient and Effective Access to Existing Customer Billing Data" was available in "sandbox" mode. The sandbox environment allowed users to explore the "Efficient and Effective Access to Existing Customer Billing Data" use case functionality with sample dummy customer data sets. This gave users an opportunity to explore the functionality and value of new features and to submit comments and suggestions without having to complete the full IEDR Green Button Connect registration process.

The IEDR Phase 2 started in April 2024. Phase 2 use cases are currently in draft status. The focus during the first months of Phase 2 has been on the improvement of the data quality of the data delivered for Phase 1 use cases and in the preparation for the testing and release of Green Button Connect (GBC) functionality. NYSEG and RG&E prepared and sent customer data deposits for this purpose. Testing of the GBC tool began in Q1 2025 and is intended to achieve GBC certification in Q3 2025.

2. Grid Model Enhancement Project (GMEP)

The GMEP is an ongoing initiative for NYSEG, and RG&E to ensure that the electric distribution assets in the field are accurately reflected in GIS and System Analysis Program ("SAP") records, and that processes are in place to sustain the data quality and accuracy in the long term effectively and efficiently.

Verification and correction of records in the SAP and GIS systems is being conducted through a field survey. Ensuring ongoing quality of data in those systems is happening through the identification of causes of discrepancies and improvements in standards and change management to implement improved processes. The field survey involves a comprehensive collection of all major asset categories for the overhead distribution network. The vendor utilizes a combination of vehicle, drone, and foot patrol collection methods to capture imagery and LiDAR information. The imagery is used to build an image recognition model that compares the field asset inventory to the SAP and GIS systems of record. Discrepancies are transmitted to the company in a prescribed data template. The contracted data integrator uses the data template to suggest and make changes to our systems of record.

The assets that are included in the field survey of approximately 45,000 circuit miles are:

- Circuits
- Poles
- Vault Pads
- Capacitors
- Cutouts
- Reclosers
- Regulators
- Sectionalizes
- Switches
- Switchgears
- Step Transformers (ST)
- Distribution Transformers (DT)

Current Progress: Describe the current implementation as of June 30, 2023; describe how the current implementation supports stakeholders' current and future needs.

The value of data resides in its availability and accuracy. The Companies recently commenced a holistic assessment of their data governance processes to ensure, and improve as needed, data availability and data quality. Currently, the assessment is still in its infancy, and additional actions and recommendations will be defined depending on its outcomes.

The Companies continue to make progress on data sharing initiatives, as detailed below:

IEDR: The IEDR platform will provide customer and system data to external third parties, including DER developers on a NYSERDA-based platform. During the IEDR Phase 1 (February 2021 – March 2024), NYSEG and RG&E shared with NYSERDA the data requested to develop Phase 1 Use Cases (Installed and Planned DERs, Hosting Capacity, Rate Plan Data, and Customer Data). Phase 2 started in April 2024 and during the first year the focus is on data quality assessment and improvement. Data shared for Phase 1 and 2 covers the following:

- Installed DERs;
- Queued DERs;
- Current and maximum hosting capacity: PV, EV and BESS;
- Rate Plan Data; and
- Customer Data.

I**nstalled and Queued DERs** are a critical component of the CLCPA. DER data is updated with a monthly cadence and contain assets of 5 megawatts or less connected in parallel with NYSEG's and RG&E's systems. Types of DER assets reported include Solar PV Systems, Energy Storage Systems, Wind, Farm Waste, Fuel Cells, Combined Heat and Power Systems, Gas Turbines, Hydro Systems and other Hybrid Combinations.

PV Hosting Capacity is an estimate of the amount of solar generation that may be accommodated without adversely impacting power quality or reliability under current configurations and without requiring infrastructure upgrades. The analysis used to create this data reflects the available feeder- and/or subfeeder-level hosting capacity for PV interconnections larger than 300 kilowatts. Data is refreshed every six months.

EV Load Capacity refers to the amount of electric power that can be supplied to EVs without overloading the grid. The EV Hosting Capacity map shows EV load capacity data that helps stakeholders decide where to site EV charging stations

BESS Hosting Capacity provides feeder- and/or subfeeder-level energy storage hosting capacity for the distribution circuits evaluated. Hosting capacity for energy storage is an estimate of the amount of charging and discharging that may be accommodated without adversely impacting power quality or reliability under current configurations and without requiring infrastructure upgrades.

Rate plan data shared with NYSERDA's Development Team is used to create a central repository of structured, machine-readable data from participating IEDR utilities. The data is in a standardized form for populating analytical tools used for rate plan modeling. It allows users to easily filter rate plans by key criteria like rate plan name or rate plan features like service type or location.

One of the objectives of Phase 2 is to implement a GBC tool to allow registered Energy Service Entities (ESEs) to digitally request authorization and receive access to **Customer Data** from all of New York's investor-owned utilities (IOUs). Access to standardized customer utility data will enable New York's third parties to speed up the deployment of clean energy in communities throughout the State. The IEDR GBC tool is currently in sandbox mode, which allows users to explore tool functionality, but without production-level data sets. Only sample dummy data will be available in sandbox mode and these data sets do not include customer utility data.

GMEP: The GMEP is a crucial project for NYSEG and RG&E and it, will identify the location and characteristics of each distribution asset on the system.[115] The end result will be an

[115] GMEP covers distribution assets 34 kV and below between substation transformers and customer sites.

accurate inventory of distribution assets on the system that will support other systems, such as EMS and ADMS, to reliably map circuits on the system.

In September 2024, the Company signed the award for the field survey capture and data integration services with two vendors. The field survey vendor immediately started with the collection of field assets through vehicle capture. Cameras mounted on vehicles capture imagery and LiDAR information. As the vehicles drive through the service territory, they are actively collecting the imagery for the overhead distribution system and all the asset categories mentioned above. The field survey continued asset capture until there were interruptions in the late November time-frame due to early Winter snowstorms through the capture territory. The vendor has used the imagery to build an image recognition model that will produce a discrepancy report between the field capture and the systems of record (SAP and internal GIS Mapping systems). Internal teams worked comprehensively through the data requirements with both the field survey and the data integrator to identify the requirements to update the Companies' asset records. The data integrator utilized the discrepancies identified in previous pilot projects to develop process flows for corrections. The Company has continuously downloaded the images as they have been collected, to build an interface for internal employees to access the images in a visual network.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2030, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2030 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation; Described where and how plans for topic-related work and investments affect the CGPP; Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

The Companies continue to work diligently on its data-sharing initiatives, including:

IEDR: Phase 2 started in April 2024 and is expected to be finalized in December 2026. Main developments to accomplish during Phase 2 include:

- **GBC:** A future enhancement of the IEDR platform will include the implementation of a GBC tool will be implemented to enable access and download customer utility data from New York State's regulated Investor-Owned Utilities (IOUs) to scope, deploy, and monitor clean energy projects. The tool will allow third party providers and customers to access customer data. Third party providers should get registered and get authorization from the customers to get access to the complete set of data. Customers will be able to authorize direct, secure transfer of their energy usage data to third parties that can assist them with ways to potentially manage and conserve energy. NYSEG and RG&E will be providing the customer data requested by NYSERDA to implement the GBC functionality in the platform.

- **Utility Energy Registry (UER) transition to IEDR:** The Commission adopted the UER in 2018 to provide communities with aggregated energy data from utilities to support climate and decarbonization planning. The UER provides a permanent supply of data to all communities so local policymakers can develop baseline GHG inventories, set mitigation goals, and track progress. Utilities report sector-based energy data at municipal, zip code, and county resolutions on January 31st and July 31st each year for the preceding six-month period. IEDR will implement the functional capabilities necessary to enable the transition, production and publication of community-scale energy usage data to the IEDR's statewide platform.

Additional efforts will focus on implementing new functionalities for the Electric Infrastructure Assessment Tool and on providing additional data related to rates and tariffs to NYSERDA's Development Team to implement a bill estimator in the IEDR's platform.

GMEP: The field survey started immediately after the execution of the contract between the field survey vendor and the Company. Vehicle drive-by capture is completed for RG&E and NYSEG. Foot patrols of pad-mount transformers started in January 2025. Drone flights for New York are scheduled to begin in late March and is expected to complete by the end of June. The Company will engage in the data validation and survey of most critical data elements in GIS (i.e., asset georeferenced location) and SAP (i.e., asset characteristics) data attributes on the distribution system in 2025. Major asset categories are expected to be updated through 2025 and completed by the end of year. Minor characteristic updates are anticipated to be excluded from the initial corrections and instead, managed through a continuation of updates into 2026. Phase tracing and phase configuration information is anticipated to be corrected starting in 2025 and continuing into 2026. Circuit configuration updates will be updated directly to the CYME (distribution loading and planning analysis tools) library which in turn produces more accurate comprehensive area studies for future grid planning.

Green Button – Download my Data: As part of the Energy Manager implementation, customers who receive an AMI meter will then be able to access a new portal within their NYSEG/RG&E "My Account." From within this portal, a customer will be able to see their interval usage via insight graphs that will help bring context to their usage when compared to similar periods, or how weather and other factors are influencing their usage. As part of these insights, a customer can then easily download their interval data in the approved Green Button standards. This file will download to the customers computer and then the customer, at their own volition, can share this with third parties that may offer additional products and energy efficiency services, or for regulatory bodies to conduct energy efficiency audits.

The exhibit below highlights the key initiatives through 2030.

EXHIBIT 2.8-1: DATA SHARING ROADMAP

Capability	Achievements (2023-2025)	Short-Term Initiatives (2026-2027)	Long-Term Initiatives (2028-2030)
IEDR	• Completion of IEDR Phase 1 • IEDR Phase 2 start. • Delivery Customer Datasets requested for the development of the GBC testing.	• Deployment of GBC functionality. • Utility Energy Registry transition to IEDR. • Completion of new Use Cases. • Completion of IEDR Phase 2	• IEDR project transition to program
GMEP	• Data governance procedures and data attributes and field codes validation. • Signature of the award for the field survey capture and data integration services. • Imagery for the overhead distribution system collection. • Image recognition model development. • Process flows corrections based on discrepancies identified. • Vehicle drive-by capture completed.	• Minor characteristic updates excluded from initial corrections to be managed through a continuation of updates.	
Green Button	• Customer usage data download and analytics available through Green Button – Download		

Integrated Implementation Timeline: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2028. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

See the exhibit above for the Companies' data sharing roadmap.

Timelines and dependencies among the work to be done are shown in Exhibits 2.8-2and 2.8-3:

EXHIBIT 2.8-2: IEDR TIMELINES

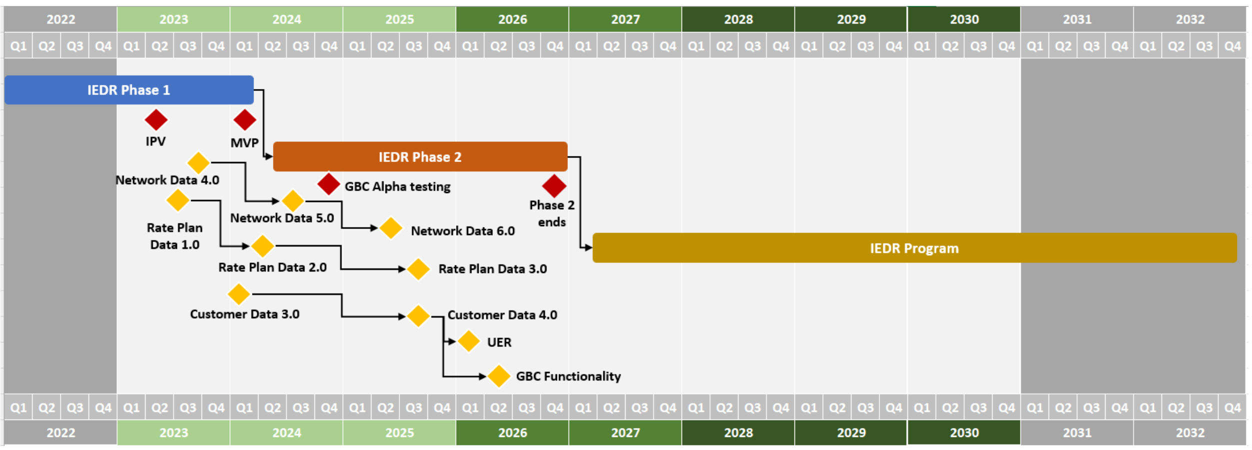
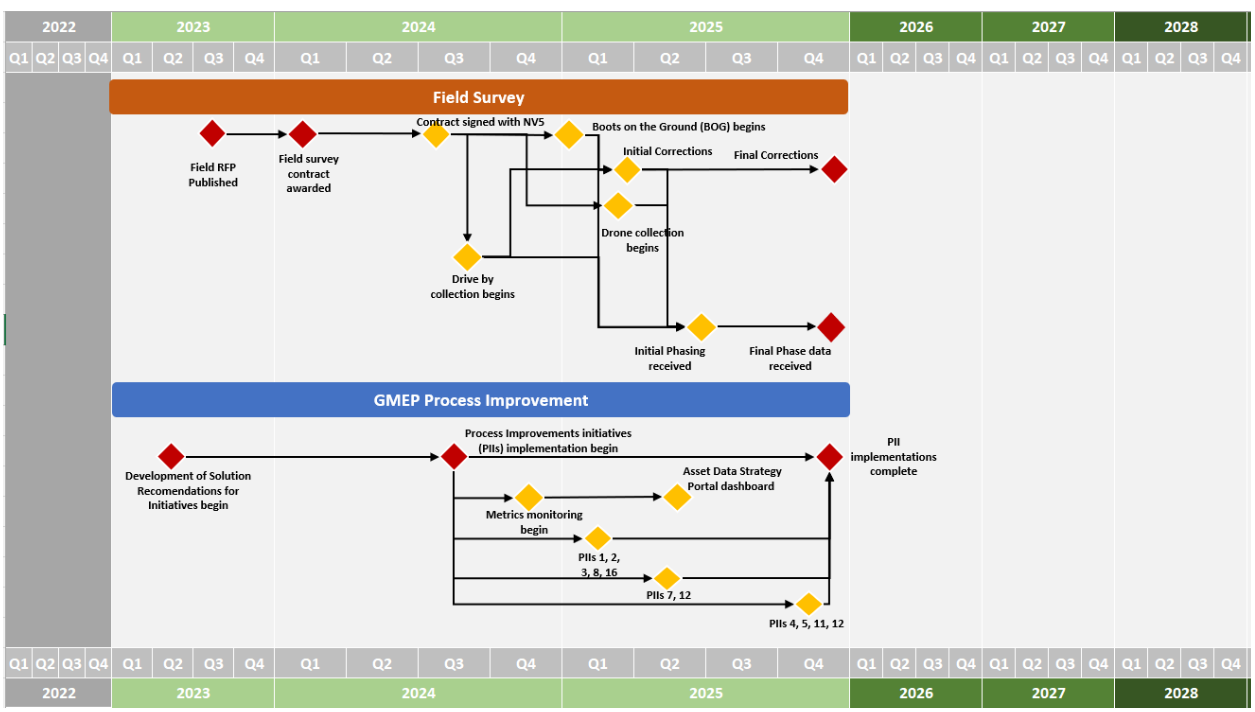


EXHIBIT 2.8-3: GMEP TIMELINES



[Risks and Mitigation]: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

The primary risks and potential mitigation measures are presented in the exhibit below.

EXHIBIT 2.8-4: DATA SHARING RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Implementation Costs:** There is a risk that the implementation costs will exceed the budget approved for Phase II.	• Extensive stakeholder engagement throughout the process of identifying, developing, and assessing new system data processes and portals.
2. **Privacy and Cyber Security:** NYSEG and RG&E or a third-party experience one or more data security breaches that impact customers.	• Case 20-E-0082 will address privacy and cyber security issues, with input from a diverse set of stakeholders • We maintain cyber security policies. • Systems that compile and communicate customer data to customers and third parties (with authorization) are designed to comply with existing North American Electric Reliability Corporation's critical infrastructure protection security standards. • Third parties are required to enter into a Data Security Agreement and maintain an Implementation and Data Protection Plan that is approved by the Commission. Avangrid Cybersecurity Risk Po •
3. **Cost Recovery:** NYSEG and RG&E will need to recover costs of providing data to third parties	• We are allowed to recover costs through a tariff for providing data to third parties if incremental costs are required to provide the data. • IEDR Phase II costs will be recovered through tariffs in the next rate case after Phase II is completed.
4. **Customer Acceptance:** Customers must trust that the DSP will protect their PII if they are to engage fully with REV opportunities	• We are testing the customer experience through the Energy Smart Community, including transactions that involve the sharing of customer data with third parties. AVANGRID has very robust security measures in place to protect customer information.
5. **GMEP Field Survey impact of Weather:** Field personnel taking photographs and flying drones may be impacted by inclement weather and storms	• Our vendors have developed a collection schedule that varies the deployment of resources throughout the three operating company territories, and can shift to a different area if weather impacts the ability to collect images.

6. **Capacity for Corrections from the Field Survey:** Corrections made to systems are limited for daily updates	• We are working to estimate the volume of updates that will result from the field survey so that we can develop the schedule for updates, and we are creating a prioritization standard for corrections and will hold lower-priority corrections should the volume exceed daily limits.

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category's needs will be met over time; Describe and explain the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

IEDR

Twice a year, the Joint Utilities of NY host a webinar to update stakeholders and take questions on matters relating to DSP services. Recordings from the JU stakeholder webinars can be found below:

- 2022 Stakeholder webinars:
  - June 23, 2022 in which the JU shared the latest progress on the DAF and general background information on the IEDR program.
  - December 16, 2022 in which the JU provided further updates on the DAF and how the PSC is looking for collaboration opportunities with the JU, including the GBC User Agreement and Onboarding Process, the DAIP, and various Orders for clarification therein.
- 2023 Stakeholder webinars:
  - July 21, 2023 (no webinar recording available) in which the JU noted the launch of the IEDR Platform and highlighted the areas where collaboration was increasing on Phase 1 activities. The JU highlighted five areas under focus for the MVP use cases, including DER siting, the EIAT, efficient access to customer billing data, find and filter rate options, and access to basic rate plan data and tariffs related to individual rates.
  - December 14, 2023 in which the JU noted a focus on data delivery

requirements for the IEDR and updates around continued work for use cases related to large DERs, consolidated hosting capacity maps, and large planned DERs for interconnection, as well as next steps for the IEDR program.

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    - 2024 Stakeholder webinars:
        - June 27, 2024 in which the JU noted process transitioning from Phase 1 to Phase 2 of the IEDR program and noted progress on the rate plan data use case.
        - December 10, 2024 in which the JU summarized activity on data set and bulk data exchanges, activities focused on Phase 2 use case development, and activity on the rate plan data use case.
- NYSERDA IEDR Stakeholder Use Case webpage Stakeholder Use Case Development - NYSERDA. A compilation of all IEDR use case submissions is available here - PDF.

GMEP

GMEP has external customer stakeholders and internal consumers of electric distribution asset data that will benefit from GMEP outcomes for improved data quality and accuracy.

The GMEP scope of work is based on the requirements of internal stakeholder groups to accurately and safely conduct their work. The list of assets and characteristics of electric distribution equipment that will be verified or updated through the GMEP Field Survey are based on the data needed to plan and execute changes to the grid and used real-time to ensure the sage and timely operation of the grid.

Corrections will be made to data in our SAP and GIS systems as they are identified through the Field Survey and process improvements required to maintain a high-level of data quality will be on-going.

GMEP relies on internal stakeholders as subject matter experts to understand and improve processes that support high data quality.

GMEP works with internal stakeholders to change processes and measure performance on improvements. The combination of the Field Survey, which will update system data, with process improvements, which will maintain accuracy, will meet the needs of the utility to have accurate information.

Process improvements made to ensure on-going data quality are designed with the users of the processes and tested before implementation. The GMEP Field Survey updates to systems include robust quality checks by both vendors and internal stakeholders.

Additional Detail

DPS Staff recommends that the DSIP Update should describe the utility's existing and planned capabilities that enable timely and effective sharing of system and customer data with customers and authorized third-parties. Shared system data should enable DER developers/operators and other third-parties to timely and effectively perform the analyses (engineering, operations, and business) needed to support well-informed decisions. Shared customer data should enable both short-term and long-term analyses and decisions affecting many investments and behaviors which can materially improve customer value by reducing costs and/or improving service.

Of particular importance to this topic is NYSERDA's development of a new IEDR. Most utility data sharing is expected to transition to the IEDR within the five-year time horizon for the DSIP update.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should:

1. *provide a functional overview of the planned IEDR;*

The PSC has mandated the creation and implementation of the IEDR platform. The creation of an IEDR platform will provide New York's energy stakeholders with a platform that enables effective access and use of such integrated energy customer data and energy system data. The IEDR aims to collect, integrate, and make useful a large and diverse set of energy related information on one statewide data platform. IEDR will perform the use cases to activate data into actionable insights and Hosting Capacity is one such use case. The IEDR will provide customer and system data to external third parties, including DER developers on a NYSERA-based platform.

To provide NYSEG/RG&E data to the IEDR platform maintained by NYSERDA we collect all the required data elements by creating data pipelines to the respective data sources. This data is stored and processed in the Azure cloud big data platform and then extracted into flat files that is required to be sent to the IEDR platform using the secure file transfer protocol ("SFTP") folder.

Hosting Capacity data sets include the geospatial information of the line segments, feeders, circuits and substations for NYSEG and RG&E. Hosting Capacity data includes sub-feeder level analyses of large-scale solar PV systems interconnecting to distribution circuits. Each circuit's hosting capacity is determined by evaluating the potential for power system criteria violations as a result of large PV solar systems interconnecting to three phase distribution lines with an alternating current ("AC") nameplate rating greater than or equal to 300 kW interconnecting to three phase distribution lines. Similarly, the same kind of data is shared for for EV Load and BESS Hosting capacity.

Data pipelines have been also developed for the rest of the Use Cases: Installed and Planned DERs, Rates and Tariffs and Customer Data, and will be developed for UER and other new Use Cases that NYSERDA requests.

2. *provide an overview of NYSERDA's IEDR implementation program, including information pertaining to stakeholder engagement;*

The IEDR Phase 1 use cases finalized in 2024, with Phase 2 use cases expected to be operational in 2026. The IEDR Development Team launched the IPV of the IEDR Platform on March 31, 2023. The IPV was the first major release of the platform to the public and demonstrated the functionality of three highly prioritized use cases. The next iteration of the platform consisted on the development of the Minimum Viable Product (MVP), which was released in March 28, 2024, including 5 additional use cases. The foundational nature of these use cases will ensure that Phase 2 achieves the program's most critical goals. Phase 2 is expected to end in December 2026.

Stakeholders have biweekly meetings to review program status, present new specifications and to discuss current and future needs. JUs and NYSERDA's development team also schedule meetings to discuss specific topics related to data sharing. Robust stakeholder engagement will continue throughout Phase 2 to ensure that a diverse reange of feedback is incorporated into the planning of future releases.

3. *provide the web link to NYSERDA's IEDR home page along with a summary of the information provided therein;*

A link to the IEDR home page can be found here: IEDR – Home page. Additional data about the different Use Cases already implemented can be found in the following links: Network Data, Rate Plan Data, Green Button Connect. A link to NYSERDA's dashboard can be found here: IEDR Program - NYSERDA. The dashboard includes information on the milestones schedule, use case development, meetings, program participants, and other IEDR resources such as NYSERDA's quarterly reports.

4. *describe the utility's role in supporting IEDR design, implementation, and operation;*

The utilities play a key role in supporting the desgin, implementation and operation of the IEDR. Their involvment is crucial to ensure the success in aggregating and providing access to energy-related data. Utilities are the primary source for data provision and integration, the ys supply datasets for the Use Cases already described:

- Hosting Capacity Maps
- Distributed Energy Resources
- Rates and Tariffs
- Customer Data.

Utilities will continue to supply data for the new use cases to be developed during Phase 2. Their participation ensures the platforme evolves to meet emerging clean energy challenges.

They participate in the Utility Coordination Group ("UCG") to ensure alignment between data governance practices, technical requirements, and addressing challenges like data security and standarization. Utilities collaborate to identify high-priority use cases and also in feedback sessions to refine platform functionality, such as the Electric Infrastructure Assessment Tool.

Utilities support customer data sharing. They enable GBC functionality, allowing customers to opt into sharing their energy data with third-party providers via the IEDR.

Utilities ensure compliace and security by adhering to strcit data security protocols mandated by the program.

5. *describe the utility's progress, plans, and investments for generating and delivering its system and customer data to the IEDR;*

For Phase 2, NYSEG and RG&E to follow the below set of 4 processes. The Companies have been working on the refinement of these 4 processes, applying lessons learned as the data sets are already flowing along this deployment process. Each of the processes defined represents different complexity and challenges.

Process #1: Manual Extraction is initiated once the Development Team has established a data request. This process involves a series of activities such as Data Discovery, system mapping, data digitization (if needed), manual data extraction and transformation, quality check and user acceptance testing, which should end with the transfer of a data set to the Development Team for their feedback. Feedback on the data set is received from the Development Team, and changes may be requested. Depending on the complexity of the data set, multiple meetings and iterations may be needed to produce a data set that meets the use case requirements.

Process #2: Data automation begins once the data set has been accepted by the Development Team. This process oversees the automation of the extraction of data from source systems, loading it into the Data Lake, transforming and consolidating it for the intended analytical use case, and loading it into the IEDR platform. Data processing tasks in the data lake may include filtering, cleansing, de-duplicating, validating, authenticating, performing calculations, translations, summarizations, conducting audits for data quality and compliance, removing, encrypting, or protecting data, and formatting the data into tables or joined tables to match the target data warehouse schema. This process requires intensive IT (Information Technology) work.

Once the process is automated, it moves to Production as **Process #3**, which runs autonomously. Finally **Process #4**: Change management has been developed due to expected modifications due to changes in internal systems and processes, or requests from the Development Team for increments, enhancements, or enabling different use cases.

Data quality issues discovered during any of those processes launch an internal process where Data Owners are notified so that they can analyze them and take the steps needed to solve them.

To ensure effective coordination and collaboration, NYSEG and RG&E have actively participated in the weekly JU IEDR Information Sharing Working Group, which provide a forum for sharing approaches to data architecture, governance, transfer options, and addressing open questions to guide the development of the IEDR design and implementation. Additionally, the Companies also participate in the JU Legal Working Group meetings to establish a unified approach for legal agreements between the utilities and the IEDR Development Team, as well as to address data transfer processes and considerations related to customer privacy and security. This emphasizes the Companies' commitment to ensuring data governance, cybersecurity, and privacy are prioritized throughout the IEDR implementation process, and actively collaborating with stakeholders to address any challenges and ensure smooth progress.

6. *identify and characterize each type of data to be delivered to the IEDR;*

Electric and gas distribution network data and Customer data is in the scope of IEDR. The information provided may include customer contact information, billing data, customer usage data from AMI, rates and tariffs data, hosting capacity maps, and relevant data for DER developers.

The following files identify and characterize each type of data to be delivered to IEDR:

IEDR_DataDictionary_
CustomerData_Templ

IEDR_DataElements_
AvangridNetworkDat

IEDR_DataDictionary_
TariffData_V002_202

7. *describe the resource(s) and method(s) used to deliver each type of data to the IEDR;*

NYSEG and RG&E had 5 FTEs as part of the IEDR Implementation team in the roles of Project Director, Business Project Manager (2), Principal Data Scientist and IT Project Manager.

In addition to that headcount, there are also numerous internal resources from different areas collaborating and supporting the IEDR use cases. The IEDR use cases involve data in three domains: Network Data, Customer Data and Tariff data. The Companies' IEDR implementation team has been working with the different domain Subject Matter Experts (SMEs) in the areas of:

- **Network Data:** The Companies' IEDR Team has collaborated with Interconnection Services, Energy Services, and Electric Transmission Services to collect the data needed for the Large Planned and Installed Distributed Energy Resources Use Cases. To share information related to the various Hosting Capacity maps, SMEs from Electric Distribution Planning have configured the data displayed on the maps. Additionally, SMEs from IT Geographical Information Systems have created the Geographical Database files to be shared with the IEDR Development Team.

- **Customer Data:** Customer Data sets require the cooperation of many different areas, such as Business Transformation, Customer Service Center of Excellence, and billing experts. SMEs from Smart Metering have been involved to work on the Interval Consumption Details data set.

- **Rate Plan Data:** SMEs from Regulatory and Tariffs have extracted the data required by the Rate Plan Data specifications from the Electric and Gas Tariff

Books and generated the files submitted to the IEDR Development Team.

- Finally, it has been necessary to get advisory support and guidance for each Use Case from Legal Services, Cyber Security and Privacy, and Information Technology Architecture.

Additional SMEs will be identified and included in project activities as needed to support the Phase 2 use cases. This collaborative effort and resource allocation demonstrate NYSEG and RG&E's commitment to the successful implementation of the IEDR program.

The Companies are implementing the deployment of the required technology to support data gathering, transformation, and transport of information to the IEDR platform using Azure Synapse and Cloud storage (Data Lake). The architecture is expected to evolve as new requirements are defined by the IEDR Development Team. The integration of NYSEG and RG&E data sets with the Data Lake will be dependent on the selection of IEDR use cases and related data elements. Currently, the integration has been made with the systems to support the data gathering and transformation for the use cases which include but are not limited to Customer Information Systems, Metering Systems, Distributed Generation Databases, ESRI (Hosting Capacity Maps) and Rates and Tariffs plans.

The Companies are looking forward to working collaboratively with DPS Staff, NYSERDA, Deloitte, Pecan Street, and the IEDR Solution Architect and Development Contractor (Development Team) to implement an internal IEDR data sourcing solution that can efficiently provide the necessary information. The Companies are committed to ensuring the successful implementation of the IEDR program and the importance of leveraging appropriate tools and technologies to ensure data quality and integrity throughout the process.

8. *describe how and when each type of data provided to the IEDR will begin, increase, and improve as IEDR implementation progresses; and,*

The IEDR is structured to roll out energy-related data incrementally across two phases (2021–2026), with datasets expanding in scope, frequency, and sophistication over time. Below is a detailed breakdown of how and when each data type will evolve as the IEDR progresses:

Utility Grid and DER Data

- Initial Release (Phase 1 – 2021–2024)
    - Hosting Capacity Data: Launched in March 2023 with the IPV, updated

annually. Enhanced in the MVP (March 2024) to include DER siting layers (environmental, terrain, community attributes).

  - DER Installation/Queue Data: Monthly updates for installed and planned DERs began with the MVP, providing real-time project tracking.
  - EV load capacity and ESS hosting capacity datasets were included in the MVP with annual updates .

- Improvements in Phase 2 (2024–2026)
  - Integration of dynamic grid performance metrics (e.g., SAIDI, SAIFI) for reliability analysis.
  - EV charger siting tools (2025) will incorporate traffic patterns, equity metrics, and utility load forecasts .
  - ESS data frequency will increase to quarterly, supporting grid resilience planning.

Rate Plans and Tariff Data

- Phase 1 (2023–2024):
  - Initial Structured Data: The MVP introduced a machine-readable Rate Plan Browser in March 2024, centralizing rate plans from investor-owned utilities (IOUs) and replacing manual PDF reviews .
  - Updates occur aperiodically (within 2 business days of regulatory changes) .
- Phase 2 Enhancements
  - Expansion to include dynamic rate modeling tools (e.g., TOU, VDER compensation) and real-time rate comparisons for commercial/industrial users.

Customer Energy Usage Data

- Sandbox Testing (Phase 1)
  - Mock billing data became available in a sandbox environment with the MVP (March 2024), allowing third-party testing without full registration.
- Full Implementation (Phase 2):

- GBC: Opt-in customer data sharing with third-party providers will launch in late 2024, enabling personalized energy efficiency and DER offers .
- Commercial/industrial customer data integration for load profiling and demand response planning .

9. *identify and characterize any existing and future utility efforts to share system and customer data with customers and third parties through means that are separate from the IEDR.*

Green Button – Download my Data: As part of the Energy Manager implementation, customers who get an AMI meter will then be able to access a new portal within their NYSEG/RG&E my account. From within this portal, a customer will be able to see their interval usage via insight graphs that will help bring context to their usage when compared to similar periods, or how weather and other factors are influencing their usage. As part of these insights, a customer can then easily download their interval data in the approved Green Button standards. This file will download to the customers computer and then the customer, at their own volition, can share this with third parties that may offer additional products and energy efficiency services, or for regulatory bodies to conduct energy efficiency audits.

The Companies currently provide data to facilitate the interconnection of DER facilities. NYSEG and RG&E each provide an Interconnection Project Queue which specific interconnection project information such as: status, division, substation and circuit id where the interconnection is planned, queue position, developer, project size, and completed milestone dates. Additionally, the Companies provide information related to planned system upgrades including a list of Qualifying Upgrades subject to cost sharing and the Companies' Capital Investment Plan. The list of Qualifying Upgrades provides information as to the division, substation, type of upgrade, a planning grade cost estimate of the upgrade, the incremental hosting capacity achieved by the upgrade, the percent funding received and a milestone schedule. The Capital Investment Plan provides details related to each capital investment plan, including the scope of the project. The Companies provide Hosting Capacity Maps to facilitate the interconnection of distributed generation ("DG"), EVSE, and energy storage. In collaboration with stakeholders and the JU, the maps will be updated on a regular basis and continue to provide additional circuit details.

2.9 Hosting Capacity

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2023 DSIP Update filing.

Hosting capacity provides an estimate of the amount of DERs that can be accommodated without compromising the power grid. New York's investor-owned electric utilities publish maps that show the estimated amount of hosting capacity along each distribution circuit. DER developers are able to use these maps to efficiently target their marketing efforts to areas where DERs are likely to require minimal investment. The Companies' hosting capacity advances focus on streamlining incoming data from the field to enable more accurate information, supported through rapid data refreshments and accurate data and process automation to reduce the required manual processes. Going forward, the Companies' hosting capacity maps will also reflect the impact of DERs service level agreements, reliability metrics, and assessment of DERs value to support grid reliability and resiliency. The Companies have made significant updates to the hosting capacity framework since the 2023 DSIP, including:

BESS Analysis: Shifted from feeder– level to nodal level assessments.

DG Integration: Incorporating DG values at the substation bank level. Updated sub bank layers with the latest GIS topology.

Map Enhancements and User Experience Improvements:

- Added **substation names** at the substation-level.
- Included **transmission node (PTID)** information at the nodal level.
- Displayed **company name** at the nodal level for improved clarity.
- Redesigned and refreshed the **EV map**.
- Created a **hosting capacity portal** consolidating all maps under a single interface with tab navigation, replacing multiple separate pages.

Data Refresh and Cost-sharing Implementation:

- Implemented full periodic refresh for **PV and BESS data.**
- Introduced **Cost Sharing 2.0** for PV and BESS projects.
- Added **DG connected/Queued values** to the BESS map

Internal Process Enhancements:

- Improved **data quality** by synchronizing GIS updates with the CYME model, ensuring consistency between GIS data pulls and model completion.
- Implemented circuit filtering to **exclude transmission circuits** and other inappropriate elements from hosting capacity map.
- Transitioned from spreadsheet-based processes to structured, controlled database source for improved data integrity and automation.

EPRI DRIVE Integration:

- Upgraded to **EPRI Drive version 4.2.1,** incorporating the latest modeling and analytical capabilities.

Current Progress: Describe the current implementation as of June 30, 2025; describe how the current implementation supports stakeholders' current and future needs.

Since 2023, the Company has developed hosting capacity maps with the following improvements.

PV Hosting Capacity map updates:

Advanced Map Functionality & Cost Share Integration (2023–2024)

- Introduced "Nodal Constraints" visualization, detailing whether hosting capacity is limited by voltage, thermal, or protection constraints.
- Incorporated Cost Share 2.0 indicators, identifying where utility-driven upgrades increase hosting capacity.
- Provided links to 8760-hour feeder load profiles, enabling developers to analyze detailed hourly load curves (where data is available).

ESS Hosting Capacity map updates:

Sub-Feeder Granularity & Nodal Constraints (2023)

- Added sub-feeder level hosting capacity analysis, increasing locational accuracy.
- Introduced color-coded nodal views, showing variations in hosting capacity across feeder sections.
- Pop-ups enhanced to show criteria violations at specific nodes (voltage, thermal, or

backfeed limits).

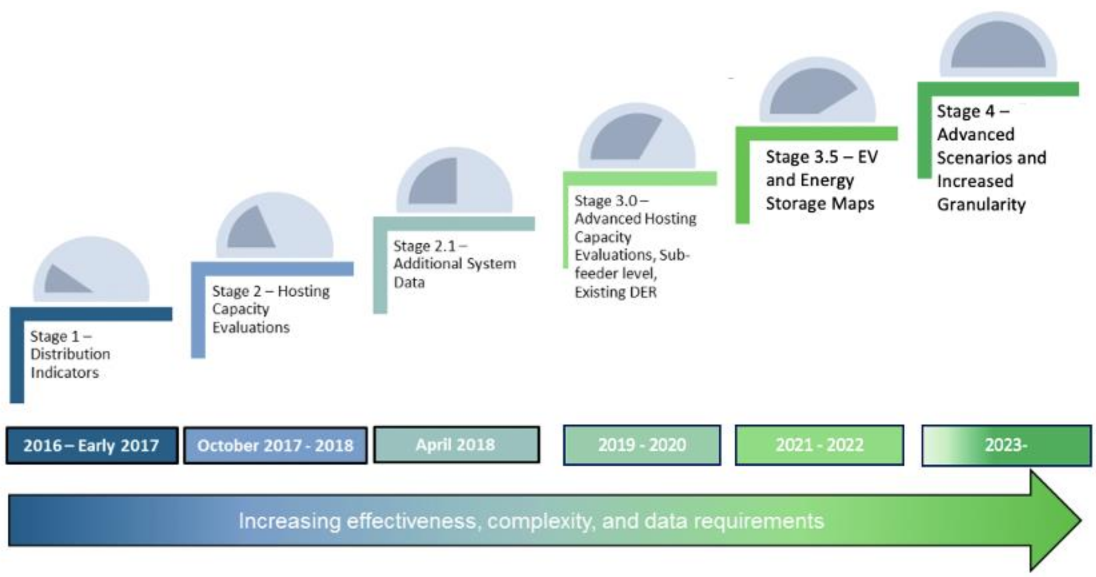
- Integrated Cost Share 2.0 project indicators for storage hosting capacity.
- Enabled REST API access for automated data retrieval.

Electrification Map Updates:
Electrification Hosting Capacity Expansion (2023–2024)

- Expanded EV Load Hosting Capacity Maps into full Electrification Hosting Capacity Maps per regulatory orders.
- Added dual seasonal hosting capacity values, allowing users to toggle between summer and winter peak conditions.

These improvements to the HC maps take into account the feedback and requests from the stakeholders and provide the increased visibility, granularity and flexibility that was requested. With these updates the developers will be able to get a better idea of a project's feasibility before the application process.

EXHIBIT 2.9-1: JOINT UTILITIES' HOSTING CAPACITY ROADMAP



As part of Stage 3.5 of the HC Roadmap, the JU published the first iteration of Storage HC Maps in spring 2022. The Storage HC Map shows feeder-level hosting capacity (min/max), additional system data, sub-transmission lines available for interconnection, and reflects existing DERs in circuit load curves and allocations. The storage HC Maps have separate displays for charging and discharging and are color-coded based on the minimum level of the maximum HC calculated for the feeder. The minimum level of the minimum HC calculated appears on the maps. Here is what the draw-down pop-up currently shows: draw-down pop-up, along with the following information.

- Refresh Date
- Hosting Capacity Max (MW)
- Section Hosting Capacity
- Feeder Rating
- Hosting Capacity Min (MW)
- Circuit Number
- Anti-Islanding HC limit (MW)
- Circuit Rating (MW)
- Circuit Voltage (kV)

The Companies also made CYME upgrades to interface with various systems, including SAP, CMESH, and GIS to incorporate DG.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2030, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2030 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation; Described where and how plans for topic-related work and investments affect the CGPP; Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

The Joint Utilities are now in Stage 4.0 of the HC roadmap, beginning implementation of advanced scenarios and increasing data granularity. Through that process, the Companies continue to collaborate with the Joint Utilities in automating processes to improve refresh rates and provide more granular data, which have been a constraint for the Joint Utilities.

The exhibit below highlights the Companies' HC roadmap through 2030.

EXHIBIT 2.9-2: HOSTING CAPACITY ROADMAP

Capability	Achievements (2023-2025)	Short-Term Initiatives (2026-2027)	Long-Term Initiatives (2028-2030)
Calculate Hosting Capacity Along Circuits	• PV and ESS Hosting Capacity map updates • Electrification Map Updates:	• Hosting Capacity Data Flows and Automation	• *(Potential)* Hosting Capacity Forecasts (to determine with stakeholder input)
CYME Upgrading and Interface	• SAP, CMESH, GIS DG	• Reflect all Existing DERs in Power Flow Analysis Automate CYME Data Flows and Calculations to Enable Frequent Updates	

The Companies Interconnections team is currently using a standard ESS schedule across the board for all BESS projects over 1MW (see below). This is due to the limited amount of load data available. However, as the line sensor project progresses, the Companies plan on using that increase in data granularity, along with other information, such as irradiance curves to define customized schedules for every battery interconnection. This will increase the accuracy of HC values as well as flexibility for BESS operation while ensuring the integrity and reliability of the grid.

Spring:
Charging: 12AM – 5AM
Discharging: 4PM – 10PM

Summer:
Charging: 12AM – 7AM
Discharging: 2PM – 9PM

Fall:
Charging: 12AM – 5AM
Discharging: 4PM – 9PM

Winter:
Charging: 12AM – 5AM
Discharging: 4PM – 9PM

<u>Integrated Implementation Timeline</u>: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2030. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

The Joint Utilities collaborate with stakeholders to prioritize developer needs. The long-term implementation timeline changes to adapt to the needs of stakeholders over time. The Joint Utilities' work to enhance the HC maps provides several benefits, including:

- Stakeholder Input: Continuous collaboration allows stakeholders and developers to provide input on the hosting capacity maps, ensuring that the maps reflect the needs and concerns of the community. This can help to build trust and transparency between the JU Integrated Planning Working Group and the community.
- Identifying Opportunities: Collaboration with stakeholders and developers can also help identify opportunities for new functionality. By working together, the JU and stakeholders can identify areas where HC Maps can be improved, which can help to accelerate the usefulness of the maps to developers.
- Better Decision Making: Collaboration with stakeholders and developers ensures that the hosting capacity maps are informed by a wide range of perspectives and expertise. This can help to improve decision-making by incorporating diverse viewpoints and ensuring that decisions are based on the best available and most up-to-date information.

  Electrification Hosting Capacity Maps were updated by January 2024, with key enhancements aimed at improving data granularity and transparency.

- Recognizing the importance of clear guidance and effective use of Hosting Capacity Maps, the Joint Utilities are preparing targeted training sessions scheduled for fall 2025. To ensure these sessions genuinely meet stakeholder needs

The exhibit below highlights the Joint Utilities' integrated implementation timeline.

EXHIBIT 2.9-3: INTEGRATED IMPLEMENTATION TIMELINE

Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

We have identified four sources of risk as shown in the following exhibit.

* PV maps have traditionally been generated in October each year, while BESS HC maps have been produced in April. There is a JU initiative to align the refresh dates for PV and BESS HC maps to April each year, starting in 2026.

**Cost Sharing 2.0 information is available on NYSEG and RG&E DG websites.

EXHIBIT 2.9-4: HOSTING CAPACITY RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Data:** DSO performance will depend on the quality data that is relied upon by the DSO to perform Hosting Capacity Analyses	• NYSEG and RG&E have proposed to implement AMI to collect more granular usage data throughout its service territory. • Build redundancy into AMI telecommunications infrastructure • Enhance Data Gateway capability to transfer SCADA data to CYME • NYSEG and RG&E have designed the GMEP to incorporate governance and data processes and flows • Prepared a data governance/data quality pilot roadmap for DER integration
2. **Uneconomic Increases in Hosting Capacity**	• Developing appropriate distribution planning criteria that will result in efficient increases in hosting capacity where needed • Changes to asset management processes to integrate new criteria
3. **Hosting Capacity Forecast Methodology:** Forecasting Hosting Capacity is a new responsibility	• Evaluating forecasting software alternatives • Implementing WattPlan Grid model throughout service territories • Collaboration with other New York utilities and EPRI • Engagement with stakeholders to confirm use cases
4. **Resource Constraints:** Limits on automation capabilities and labor hours to implement	• Using contractors to refresh CYME models • Work with GIS and Master to remove errors from GIS which will reduce the amount of hours required to clean-up CYME models
5. **Refresh dates:** move the HC refresh to April. There is time required to process summer peaks that currently is a manual process.	• Assign resources as soon as the summer period ends, October 31st to process the summer peaks • Line Sensors implementation and more SCADA reads will automate the summer peaks readings

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category's needs will be met over time; Describe and explain the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how *the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.*

The JU Integrated Planning WG hosts two stakeholder sessions each year. The sessions inform the next iteration of the HC Maps and guide the Joint Utilities in providing further functionality. The Joint Utilities host two stakeholder sessions per year. During these stakeholder sessions, the Joint Utilities provide stakeholder an update and also encourage discussion, suggestion and feedback, inviting over 500 stakeholders to each session. Key stakeholders include DER developers, EV charging companies as well as non-profits seeking to accelerate the adoption of clean energy, such as the Interstate Renewable Energy Council ("IREC") and New York Battery and Energy Storage Technology Consortium ("NY-BEST").

The current iteration of the Hosting Capacity Maps for PV, ESS, and Electrification directly supports stakeholders by providing detailed, transparent, and accessible grid capacity data that informs decision-making across sectors. Developers can use the maps to identify optimal project locations and streamline interconnection planning,

Stakeholders have expressed their desire for more granular data, easier data access, or new map types. The 2025 HC updates and the line sensor project aim to satisfy these requests. All types of developers will benefit from the changes made this year. However, ESS developers will find the greatest benefits will come when the line sensor program is complete as the more granular load data will provide visibility into the circuit specific load curves that will help provide more accurate ESS HC values.

The Joint Utilities' hosting capacity working group organizes all stakeholder engagement activities related to hosting capacity. This working group focuses specifically on hosting capacity maps and needed improvements based on developers' input to the maps. Aligning HC map needs and ensuring consistency between utilities is key. The Joint Utilities have engaged in extensive stakeholder consultations in designing the multi-stage approach to hosting capacity. The Joint Utilities continue to meet with stakeholders and will schedule future meetings to occur during the design phase of a new release or to obtain feedback after each new release and discuss future enhancements.

For 2025, the Joint Utilities Integrated Planning Working Group are preparing targeted training sessions scheduled for the fall of 2025. The JU has actively sent out a survey with questionnaires seeking feedback on stakeholder's familiarity with the Hosting Capacity maps. Results from this survey will dictate what topics the fall 2025 training would be covering.

Hosting capacity information is of particular importance to DER developers as it allows prospective interconnection customers to make more informed business decisions prior to committing resources to an interconnection application. DER developers are able to use HC maps to locate DERs cost-effectively. For example, in 2021, before the Energy Storage HC maps were launched, the Joint Utilities held stakeholder sessions to better understand developer needs. Due to these stakeholder sessions, the Joint Utilities added functionality to the Energy Storage HC maps that the group had not previously considered. Joint Utility stakeholders continue to improve on BESS maps in 2025 by updating these maps to section level and include color coded nodal views showing variations in hosting capacity across feeder sections and different pop-up values to indicate criteria violations similar to PV HC map.

After the Joint Utilities published the first iteration of the Storage HC maps, stakeholders requested that the maps utilize use cases that reflect developer business models. Currently, use cases for the storage capacity map are worst-case scenario. To share use cases that better reflect developer business models, the Joint Utilities invited stakeholders to share their business use cases with the ITWG. While these will not be interconnection use cases, the goal is that there is alignment on approach to information between interconnection and the hosting capacity maps.

Additional Detail

Providing an electric distribution system with the capacity to host large scale DER integration is a key part of New York's energy vision. To achieve that outcome, the utilities must perform several functions to ensure that large amounts of DERs can access and utilize hosting capacity in ways that are affordable, effective, efficient, and timely. The utilities have made significant early progress in producing and sharing information about the hosting capacity of their current systems. DER developers and other stakeholders value the new information as a significant improvement to the information which was previously available to them; however, more is needed in three areas.

First, as DER developers and other stakeholders access and use the utilities' hosting capacity information, it is becoming increasingly evident that assessments of currently available hosting capacity do not adequately inform DER development processes and decisions. DER developers and the utilities would both be better informed by hosting capacity forecasts which look ahead three to five years. Once available, such forecasts would become the preferred resource for planning DER development.

Second, as grid operations evolve to accommodate and optimize significant DER development, some of those operations will come to rely on the availability of hosting capacity as a managed system resource. Such operations will continually require very *current information about available hosting capacity throughout the distribution system. This means that the utilities should be prepared to timely increase the rate at which they produce and share their information about currently available hosting capacity.*

And third, the availability of ample hosting capacity at a given location on the grid does not necessarily mean that other factors (i.e. space, accessibility, safety, zoning, customer interest, etc.) will also favor deploying a DER at that location. At the same time, there are many locations where circumstances strongly favor DER development; however, the amount of hosting capacity available at those locations is inadequate. This could mean that utilities will need to take measures to increase hosting capacity at attractive DER development sites in order to support the State's goals for integrating renewable energy resources. Considering these points, the utilities should be prepared to timely increase hosting capacity in their distribution systems.

DPS Staff recommends that the DSIP Update should address the three areas addressed above and provide detailed information related to assessing current hosting capacity, forecasting hosting capacity, and increasing hosting capacity to show that the utility is timely developing – either individually or jointly with one or more of the other utilities – the necessary information resources and capabilities associated with hosting capacity.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to hosting capacity:

1) *Describe the utility's current efforts to plan, implement, and manage projects related to hosting capacity. Information provided should include:*

    a. *a detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long range hosting capacity plans;*

        Since 2023, the Companies have implemented additional HC map improvements such as Advanced Map functionality and cost share integration. Sub feeder granularity & nodal constraints as well as Electrification HC expansion. These updates were completed as part of Stage 4.0 of Joint Utilities' Hosting Capacity roadmap, as discussed in the Current Progress section above.

    b. *the original project schedule;*

        The original project schedule was decided through Joint Utilities' efforts and developments and continues to change as needed.

c. the current project status;

The Joint Utilities hosting capacity working group will continue to meet and focus on the development of Stage 4.0. The Joint Utilities plan to continue to meet with stakeholders to build agreement on the timing of future meetings with the release of new iterations of the hosting capacity displays, focused on advanced scenarios and increased map granularity. The timing of this approach provides stakeholders a forum to engage with the Joint Utilities directly on new material, and also to provide input that will inform future stages.

d. lessons learned to-date;

Maintenance/Upgrade of Hosting Capacity require an intensive effort from utilities. Automation will help with this and is one of the only ways to improve hosting capacity maps.

e. project adjustments and improvement opportunities identified to-date; and,

Hosting capacity map adjustments are made throughout the project to address stakeholder needs, which change over time.

f. next steps with clear timelines and deliverables

The Joint Utilities are now in Stage 4.0 of the HC roadmap, beginning implementation of advanced scenarios and increasing data granularity. Stage 4.0 will involve more granular and segment-based hosting capacity maps and information, whereas previously this data was circuit-based. This will assist developers in assessing whether a particular location is able to accommodate a resource.

As part of the progression to Stage 4.0, the Joint Utilities are reviewing and will consider the following issues that have been identified by DER developers:

- EPRI DRIVE Utility Inputs, Analyses Used, and Study Parameters Transparency
- Better Communication of Available Reference Materials and Supporting Documentation
- Upstream Substation/Bank-Level Constraints
- Hosting Capacity Analysis Criteria Violation Transparency
- Hosting Capacity Data Validation Efforts
- Circuit Equipment Ratings
- Additional Map functionality (downloadability/filterability)
- Increased Analysis Refresh Rate

- Hosting Capacity Analysis for Energy Storage
- Hosting Capacity for Combined Heat & Power
- Hosting Capacity for Electric Vehicles
- Hosting Capacity for Hybrid Solar + Storage
- Time-Varying Hosting Capacity (increased temporal granularity)
- Forecasted Hosting Capacity
- Dynamic Hosting Capacity

2) *Describe where and how DER developers/operators and other third parties can readily access the utility's hosting capacity information.*

NYSEG, RG&E, and other New York utilities communicate hosting capacity by posting maps to their respective company websites as a first stop for DER developers considering development in a particular neighborhood or area.[116]

3) *How and when the existing hosting capacity assessment information provided to DER developers/operators and other third parties will increase and improve as work progresses. This should include discussion of the transition of hosting capacity information access from the utility's current hosting capacity information portal to the statewide hosting capacity solution in development on the Integrated Energy Data Resource ("IEDR").*

Our hosting capacity assessment will improve as the actions below are implemented:

- AMI, grid automation, and other foundational investments produce actual usage and system performance data that is reflected in hosting capacity updates;
- Completion of our GMEP project;
- Updates to our network configuration to reflect infrastructure development on a more timely basis;
- Completion of the CYME Gateway software project, which automates the process of populating circuit models with SCADA data;
- PV maps show the criteria that are violated so developers can better understand what is limiting the HC at a certain section
- Early 2023 marked the IEDR's IPV, which included the first statewide HC map consolidation. At that stage, the IEDR essentially mirrored each utility's published HC maps in a single viewer, displaying key attributes like available capacity per

116 NYSEG and RG&E hosting capacity portal is available here.

circuit section; and

- In April 2023, the Joint Utilities collectively rolled out a suite of enhancements to their Hosting Capacity analyses, which were subsequently fed into the IEDR. These included: sub-feeder level hosting capacity for energy storage (providing node-level granularity on storage interconnections), identification of nodal constraints (violation criteria) on the PV and storage maps, an indication of how much DER has been connected since the last HC refresh,

Additionally, since hosting capacity updates require extensive manual activities, the refreshes planned for Stage 4.0 will not include DER projects below 500 kW. These smaller projects may be included in the future once we are able to further automate the refresh process. This ability is dependent on the steps above.

4) *Describe the means and methods used for determining the hosting capacity currently available at each location in the distribution system.*

All the Joint Utilities use EPRI's DRIVE tool to calculate hosting capacity. The hosting capacity maps began with feeder-level data, which have been upgraded to provide section-level data since the last DSIP. The EVSE maps were completed in 2020 and, provide feeder/circuit level data. Each circuit's hosting capacity is currently determined by evaluating the potential power system criteria violations as a result of large solar PV systems with an AC nameplate rating starting at and gradually increasing from 500 kW, interconnecting to three-phase distribution lines. The analyses represent the sub-feeder level hosting capacity only and do not account for all factors that could impact interconnection costs (including substation constraints). Interconnection queue data is updated monthly. Since the release of the last DSIP, changes in Interconnection Queue will be updated on a monthly basis on PV HC maps. As of today, BESS HC map is at the nodal level to match that of the PV Maps.

As a rule of thumb, the minimum hosting capacity value is indicative of the available hosting capacity across the length of the feeder segment and most often defined by the hosting capacity value located at the most downstream node within each breakpoint. The maximum hosting capacity value is indicative of the available hosting capacity at a specific location across the feeder segment, usually located at the most upstream node within each breakpoint.

PV maps now include section by section data. Developers raised through JU stakeholders meetings that they will like to understand why HC is limited to it what it is showing. JU have gone above and beyond this ask and our PV HC map now show each of the category that was used to calculate HC and what value of HC is avaiable for each

HC. This will help developers what type of mitigation may be to increase HC of a certain feeder.

- Section ID
- Feeder
- Base Voltage (kVLL)
- Section Hosting Capacity (MW)
- Bank Rating (MW)
- Feeder Rating (MVA)
- Flicker Value (MW)
- Primary Over-Voltage Deviation (MW)
- Primary Voltage Deviation (MW)
- Regulator Deviation (MW)
- Thermal from Generation (MW)
- Anti-Islanding

5) *Describe the means and methods used for forecasting the future hosting capacity available at each location in the distribution system.*

All of the Joint Utilities' members use EPRI's DRIVE tool to calculate hosting capacity. The Joint Utilities are beginning to discuss forecasting hosting capacity and plan to convene with stakeholders as well. In the future, we will need to build additional CYME models that reflect the anticipated completion of future projects in the capital budget forecast. Currently, CYME models are refreshed annually and EPRI Drive tool is used to calacualte HC.

6) *Describe how and when the future hosting capacity forecast information provided to DER developers/operators and other third parties will begin, increase, and improve as work progresses.*

Future hosting capacity plans are driven by upgrades and changes that the Joint Utilities have agreed to.

7) *Summarize the utility's specific objectives and methods for:*

   a. *identifying and characterizing the locations in the utility's service area where limited hosting capacity is a barrier to productive DER development, directing users to the CGPP filing for further information; and,*

      The current PV hosting capacity maps provide section-level data.

   b. *timely increasing hosting capacity to enable productive DER development at those locations, directing users to the IEDR platform when applicable for more information.*

      Changes to distribution planning criteria that increase hosting capacity by reflecting the benefits of increasing hosting capacity when designing asset management solutions is the most economical solution to increase hosting capacity. We do not believe that a "build it and they will come" strategy will be efficient or economic and is more likely to impose extra costs on our customers.

      An alternative and preferred approach is to incorporate more granular DER measurement, monitor, and control (MM&C) into grid optimization schemes to enable more connections to a circuit. Currently, the Companies are waiting on the AMI and Line Sensor Program implementation to gather more granular data of the circuits.

2.10 Billing and Compensation

<u>Context/Background</u>: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2023 DSIP Update filing.

On July 17, 2015, the Commission authorized CDG, enabling customers for whom rooftop solar was not an option to participate in renewable energy programs.[117] The CDG participants receive credits on their utility bills and in return pay the CDG sponsor a monthly subscription fee. A CDG project consists of a generation facility eligible for net metering located behind a host meter. Membership in a CDG project is limited to utility customers that do not participate in net metering projects directly or remotely. Each CDG project has a sponsor, that is responsible for building and operating the facility. The sponsor is also responsible for coordinating with the Utility and managing membership. The role of the Utility is to distribute the credits from the generation facility in accordance with the sponsor's instructions.

On March 9, 2017, the Commission directed an immediate transition away from net energy metering ("NEM") to a VDER Phase One tariff, which included two components:[118]

1. Implementing a new DER program similar to NEM with a 20-year compensation term limit; and
2. The Value Stack tariff implementing a new, more comprehensive DER program based on monetary crediting for net hourly injections.

The VDER/Value Stack tariff replaces net energy metering for valuing injection of electricity onto the grid from distributed generation. Any solar, wind, hydroelectric, farm-based anaerobic digesters, geothermal, tidal, renewably power storage, or stand-alone storage facilities with capacity less than 5MW qualify for the VDER tariff. The Value Stack provides precise monetary value to each kWh procured by DERs based on location and timing. The components of VDER include energy value, capacity value, environmental value, demand reduction value, and the locational system relief value.

On September 14, 2017, the Commission ordered, among other things, that each utility use a process that ensures that each CDG member receives his or her credits no more than

[117] Case 15-E-0082, Proceeding on a Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program, Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015) (CDG Order).

[118] Cases 15-E-0751 et all., In the Matter of the Value of Distributed Energy Resources (VDER Proceeding), Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017).

two months following the end of the billing cycle.[119] The Joint Utilities were also directed to consider implementing automation and consolidated billing.

On December 12, 2019, the Commission approved the Net-Crediting model for consolidated billing for CDG projects allowing for the CDG subscription fee to be included on the customer's utility bill simplifying the process for CDG members who would only receive a single monthly utility bill.[120] On February 4 2020, NYSEG and RG&E filed theirs Community Distributed Generation Net Crediting Program Implementation Plan.[121] The Commission required that the Joint Utilities include anticipated timelines for implementation of net crediting, cost estimates, estimates of costs that are incremental to current rate recoveries, as well as an accounting plan for deferral of incremental revenue requirements.

On March 29, 2022, Staff filed its Straw Proposal on Opt-Out CDG that, among other things, provided recommendations related to CDG billing, generally aimed at addressing ongoing issues.[122]

On March 31, 2021, and March 31, 2022, NYSEG and RG&E filed their annual CDG net crediting modeling reports, pursuant to the ordering requirements of the December 2019 Net Crediting Order.[123] The Companies file annual reports of the costs with implementation and operation of the net crediting model, as well as the amount recovered through the discount rate on March 31st of every year.

On September 15, 2022, the Commission ordered the Joint Utilities to file Implementation Plans detailing the progress toward automation of crediting and billing of CDG projects and

[119] Case 15-E-0751 - In the Matter of the Value of Distributed Energy Resources. CASE 15-E-0082 – Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program. Effective September 14, 2017.

[120] Case 19-M-0463, In the Matter of Consolidated Billing for Distributed Generation (CDG Proceeding), Order Regarding Consolidated Billing for Community Distributed Generation (issued December 12, 2019) (CDG Order).

[121] CDG Proceeding, NYSEG and RG&E Community Distribute Generation Net Crediting Program Implementation Plan (filed February 4, 2020).

[122] CASE 14-M-0224 – Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs. CASE 15-E-0082 – Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program. CASE 19-M-0463 – In the Matter of Consolidated Billing for Distributed Energy Resources. DEPARTMENT OF PUBLIC SERVICE STAFF STRAW PROPOSAL ON OPT-OUT COMMUNITY DISTRIBUTED GENERATION Dated March 29, 2022

[123] CDG Proceeding, NYSEG and RG&E Annual CDG Net Crediting Modeling Report (filed March 31, 2021, and March 31, 2022).

initiated a stakeholder conference to focus on CDG crediting and billing performance metrics and a negative revenue adjustment.[124] The implementation plans included:

1. The current billing system constraints preventing full CDG billing automation.
2. The billing system changes necessary to effectuate automated CDG billing.
3. The steps and timelines to achieve full automation of CDG billing.

The Joint Utilities are now involved in the CDG billing and crediting negative revenue adjustment stakeholder conference process, initiated by the September 15, 2022, Commission Order.[125] Additionally, NYSEG and RG&E, along with the rest of the Joint Utilities, meet with Stakeholders and Commission Staff monthly through the Billing and Crediting Working Group.

On May 16, 2024, the Commission ordered the Joint Utilities to implement a program which allows generation customers that would otherwise be eligible to be a Net Credited Community Distributed Generation ("Net Credited CDG") Host account to instead be a Statewide Solar For All ("S-SFA") Host account.[126] The generation under both programs is valued based on the Value Stack calculations. there are no subscribers; the VDER credits are split three ways at the Host level: The Utility Administration Fee, the Project Pool/Customer Share, and the Host Compensation Level. Once a year, the dollar amount in the above-mentioned account is used to create an equal monthly credit to be applied to Energy Assistance Program ("EAP") electric customers that are located in DACs.

On May 16, 2024, the Commission orders the Joint Utilities to implement multiple Community Distributed Generation savings rates and to allow up to three CDG savings rates and the exclusion of multiple anchor customers for CDG projects.[127] The Joint Utilities

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[124] CDG Proceeding, Order Establishing Process Regarding Community Distributed Generation Billing (issued September 15, 2022).

[125] Case 19-M-0463 – In the Matter of Consolidated Billing for Distributed Energy Resources. CASE 15-E-0082 – Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program. CASE 14-M-0224 – Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs CDG Proceeding, Order Establishing Process Regarding Community Distributed Generation Billing (issued September 15, 2022).

[126] Case 21-E-0629 - In the Matter of the Advancement of Distributed Solar. Case 19-E-0735 – Petition of New York State Energy Research and Development Authority Requesting Additional NY-Sun Program Funding and Extension of Program Through 2023. Case 14-M-0224 - Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs, ORDER APPROVING STATEWIDE SOLAR FOR ALL PROGRAM WITH MODIFICATIONS Issued and Effective: May 16, 2024

[127] Case 21-E-0629 - In the Matter of the Advancement of Distributed Solar. Order approving multiple savings rates for community distributed generation subscribers (issued May 16, 2024)

are directed to complete implementation of these policy changes within one year of the issuance of this Order. On August 16,2024[128], NYSEG and RG&E filed a report including estimated costs for customer information system and billing system modifications necessary to implement the directives of the Order, as discussed in the body of the Order.

On October 16, 2024, the Commission ordered the Joint Utilities to implement a program where Customers can dual-participate with opt-in CDG called Renewable Energy Access and Community Help program (REACH).[129] Once a year, the dollar amount in the above-mentioned account is used to create an equal monthly credit to be applied to EAP electric customers that are located in DACs.

On December 15, 2024, the Commission ordered the Joint Utilities to file Implementation Plans detailing:

1. The process to automatically enroll or un-enroll customers in the REACH program once the utility receives notification of the customer's eligibility for EAP enrollment/un-enrollment.

2. A customer outreach and education plan

Estimated costs for customer information system and billing system modifications upgrades required for REACH program implementation. As part of the estimated costs provided, the Joint Utilities shall indicate if any of these costs are incremental to the costs related to S-SFA implementation."

On December 20, 2024, the Commission ordered the Joint Utilities to implement a Volumetric Net Crediting program for volumetric community distributed generation projects and fully automate billing within 12 months of the effective date of this Order.[130]

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[128] NYSEG & RGE of Estimated Costs of Customer Information System and Billing System Costs to Implement Directives of May 16, 2024, Statewide Solar for All Program Order (filed August 16, 2024).

[129] CASE 24-E-0084 - Petition of New York Power Authority to Establish the Renewable Energy Access and Community Help Program. ORDER IMPLEMENTING RENEWABLE ENERGY ACCESS AND COMMMUNITY HELP PROGRAM Issued October 16,2024

[130] CASE 19-M-0463 - In the Matter of Consolidated Billing for Distributed Energy Resources. ORDER APPROVING NET CREDITING FOR VOLUMETRIC COMMUNITY DISTRIBUTED GENERATION PROJECTS (Issued and Effective December 20, 2024)

On March 1, 2025, NYSEG and RG&E filed an annual report with the Commission detailing the amount of the one percent administrative fees collected by each utility and the costs to implement the REACH program.[131]

Current Progress: Describe the current implementation as of June 30, 2025; describe how the current implementation supports stakeholders' current and future needs.

Methodologies to compensate DERs for injections into the electric grid have evolved from NEM to a methodology that compensates DERs for the value they provide to the electric grid (i.e., VS). To smooth the transition, the Commission developed Phase One compensation to lessen the impact on residential and small commercial customers.[132] In addition to compensation methodologies, the Commission has developed numerous programs that offer more customers that ability to enjoy clean energy benefits, regardless of their ability to install onsite generation (e.g., CDG and Remote Crediting ("RC").[133] Over time, these compensation methodologies have evolved to include additional types of assets and value streams. The Company has engaged proactively with DPS Staff, DER developers, and interested stakeholders during this development process.

The Companies have implemented and automated numerous compensation methodologies, some of which are automated, for DER billing including the following:

- NEM;
- NEM Successor;
- VDER;
- Remote Net Metering ("RNM")/Remote Credit;

[131] Statewide Solar for All Program and Renewable Energy Access and Community Help Program Implementation Cost Report Filed February 8, 2025

[132] Case 15-E-0082, Proceeding on a Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program, Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015) (CDG Order).

[133] CASE 19-M-0463 - In the Matter of Consolidated Billing for Distributed Energy Resources. Issued and Effective: December 12, 2019, CASE 24-E-0084 - Petition of New York Power Authority to Establish the Renewable Energy Access and Community Help Program. ORDER IMPLEMENTING RENEWABLE ENERGY ACCESS AND COMMMUNITY HELP PROGRAM Issued October 16,2024 Case 21-E-0629 - In the Matter of the Advancement of Distributed Solar. Case 19-E-0735 – Petition of New York State Energy Research and Development Authority Requesting Additional NY-Sun Program Funding and Extension of Program Through 2023. Case 14-M-0224 - Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs, ORDER APPROVING STATEWIDE SOLAR FOR ALL PROGRAM WITH MODIFICATIONS Issued and Effective: May 16, 2024, CASE 19-E-0735 - Petition of New York State Energy Research and Development Authority Requesting Additional NY-Sun Program Funding and Extension of Program through 2025. ORDER AUTHORIZING CHANGES TO THE REMOTE CREDITING PROGRAM (Issued and Effective July 15, 2021)

- CDG
- Host Community Benefit Program Statewide Solar For All (SSFA); and
- Renewable Access and Community Help program (REACH).

The Companies have implemented the numerous changes required by the Commission and continuously collaborates with stakeholders, through working groups and technical conferences, or on a one-to-one basis to understand the needs of DER suppliers while balancing the interactions with existing programs and Commission policies and the capabilities of the Companies' billing systems.

Grandfathered Net Metering ("NM")

Projects that met the requirements, set forth in the VDER Transition Order, to receive compensation under NEM will continue to receive such compensation under Grandfathered NM. These requirements include type of generation, rated generation capacity, and date of interconnection and must be met as of March 9, 2017.

Net Energy Metering Successor

The VDER Transition Order recognized the importance of offering compensation mechanisms that "ensure[s] all customers pay their fair share for the costs of grid operation and benefit from the value they provide." To this end, residential customers with onsite solar generation who are compensated under the NEM Successor methodology are required to pay a Customer Benefits Charge ("CBC") in order to shoulder their fair share of costs for certain EE and other public policy benefit programs.

Value of Distributed Energy Resources

The Companies have implemented compensation methodologies required by the VDER Transition Order, as updated. VDER replaced the NEM compensation methodology on a prospective basis with Phase One NEM compensation or VS compensation, eligibility for which is dependent on specific date requirements. Phase One NEM is a transitional methodology that the Commission offered to projects that were in advanced stages of development. The VS compensation methodology seeks to compensate eligible DERs for the value of energy injections provided to the electric grid. Compensation under the VS compensation methodology for net hourly injections is calculated based on the values associated with Energy (Locational Based Marginal Price or "LBMP"), Capacity ("ICAP"), Environmental Value ("E Value"), Demand Reduction Value ("DRV"), and Locational System Relief Value ("LSRV"). Both the VDER Transition Order and the VDER Implementation Order acknowledged that the initial VS compensation methodology was transitional and would change and develop over time. Accordingly, the Commission has instituted numerous changes, including changes to some of the VS VDER Proceeding, Order on Net Energy Metering Transition, Phase One of VDER, and Related Matters (issued March 9, 2017[134]) ("VDER Transition Order"), VDER Proceeding, Order on Phase One VDER Implementation Proposals, Cost Mitigation Issues, and Related Matters (issued September 14, 2017) ("VDER Implementation Order").[135] components, establishment of a Community Credit and Community Adder, and changes to the rules for banking of excess credits on a subscriber's account. Further, the Commission expanded the VS compensation methodology to include availability to previously ineligible technologies, such as standalone storage assets. This expansion required changes to the availability of certain VS compensation methodology components, such as the E Value. Subsequently, the Commission expanded the VS compensation methodology to include availability to hybrid facilities (*i.e.,* energy storage systems paired with eligible electric generating equipment).

Remote Net Metering/Remote Crediting

RNM was available to commercial customers with onsite generation that wish to share the benefits of that generation with their other accounts, thereby reducing the electric utility bills of multiple accounts of the onsite customer. In 2020, the Commission established the RC compensation methodology and required that all RNM projects that received compensation under the VS compensation methodology be converted to RC. The application of credits to subscribers of a RC project differs from the application of credits to RNM subscribers. Specifically, RNM follows a cascade crediting process in which subscribers receive credits one after another until the entire excess generation amount is exhausted, whereas RC is allocation based. In addition, the subscriber requirements for non-VS RNM, RC and CDG are different. RNM subscribers must be related; RC subscribers are limited to ten unrelated members, each of whom can have any number of additional participating accounts, and CDG subscriber lists must contain a minimum of 60 percent mass market customers and be over 10 customers. In addition, subscribers to a RC project may subscribe to more than one RC project and may have onsite generation; in contrast

[134] Cases 15-E-0751 et all., In the Matter of the Value of Distributed Energy Resources (VDER Proceeding), Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017).

[135] CASE 15-E-0751 - In the Matter of the Value of Distributed Energy Resources. CASE 15-E-0082 – Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program. Effective September 14,2017VDER Proceeding, Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters (issued September 14, 2017) (VDER Implementation Order).

CDG subscribers may subscribe to only one CDG project and are prohibited from having onsite generation.

Community Distributed Generation

The CDG Order established the framework for CDG projects whereby customers, or subscribers, participate in a CDG project, owned and operated by a third party that allocates a percentage of the CDG project's generation to the subscribers.[136] The utility is responsible for crediting the value of that generation, based on the applicable compensation methodology, on the subscribers' electric utility bills. In addition to the VS components listed above, CDG projects are eligible for a Market Transition Credit ("MTC"). The MTC is intended to compensate residential and small commercial customers for the change from NEM to VS. Eligibility for MTC was limited to projects that applied for interconnection early in the transition to VS, to compensate projects that may have relied on a different form of compensation when seeking financing. The Company works closely with CDG Hosts to set up, bill, and credit both the CDG Host and the project's numerous subscribers. NYSEG and RG&E established processes for the monthly submittal and acceptance of Subscriber Allocation Forms, leveraging the Companies' SFTP site. This process enables the tracking of forms and supports the automation of credit billing. To ease the administrative burden on CDG Hosts and encourage more customers to participate in CDG, the Commission required utilities to offer consolidated billing for CDG projects compensated under VS Known as NC, this program requires that utilities collect the subscription fees that previously were billed by the CDG Host from customers.[137] These subscription fees reduce the amount of the credit that is applied to a subscriber's electric bill. The Company enters agreements with each participating CDG Host and remits payments on a monthly basis to the CDG Host based on the savings rate (*i.e.*, the percentage of the credit retained by the customer) prescribed by the CDG Host. Transparency of information supports increased deployment of DERs in New York. As discussed below, increased information on customer bills shows the benefits that customers receive by supporting clean energy assets. DER providers can leverage Company-provided information to offer tailored products to their customers. The Company provides monthly subscriber level reports to each CDG Host detailing the credits applied,

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[136] CASE 15-E-0082 - Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program. ORDER ESTABLISHING A COMMUNITY DISTRIBUTED GENERATION PROGRAM AND MAKING OTHER FINDINGS Issued and Effective: July 17, 2015

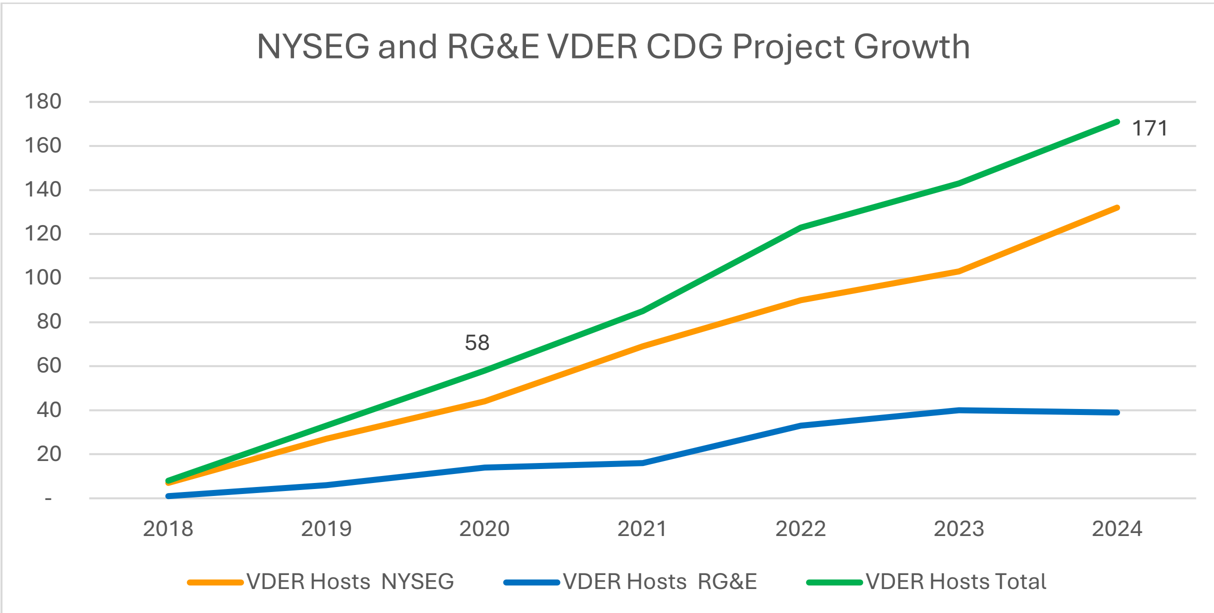
[137] CASE 19-M-0463 - In the Matter of Consolidated Billing for Distributed Energy Resources. ORDER REGARDING CONSOLIDATED BILLING FOR COMMUNITY DISTRIBUTED GENERATION Issued and Effective: December 12, 2019

and any excess credits banked, among other information. Subscriber's subscription fees are also detailed for those participating in a project participating in NC. The Company collaborates with CDG Hosts to understand their needs and provide requested information, as available.

As of December 31, 2024, the Companies bill 218 CDG projects with a total of approximately 68,000 subscribers. Of those projects,130 participate in NC. The Companies work closely with the DER providers offering projects in its service territory to meet the providers' needs and understand their business. NYSEG and RG&E actively participates in the increased adoption of DER by receiving and processing monthly allocation forms, calculating monthly credits, providing customer level information to the DER provider, and sending monthly payments to those providers participating in NC. This collaboration enables DER providers to offer more projects, thereby increasing the amount of solar deployed in the State and offering the opportunity for all customers in NYSEG and RG&E service territory to support and enjoy the benefits of solar. The Companies also support low-income customer participation in solar by supporting the crediting of customers who participate in NYSERDA's Solar For All program.

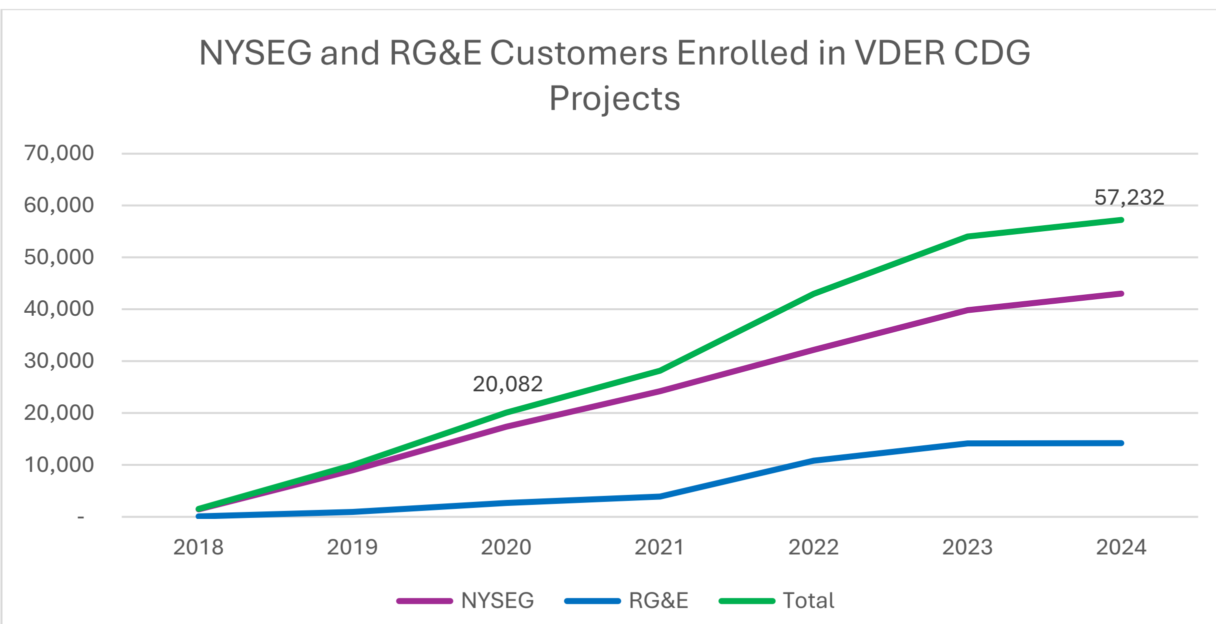
Billing automation is necessary to support the widespread adoption of CDG projects in the Joint Utilities' service territories and provide timely and accurate billing for customers. From 2020-2024, the number of VDER CDG project hosts has more than tripled as shown in Exhibit 2.10-1

EXHIBIT 2.10-11: NYSEG AND RG&E VDER CDG PROJECT GROWTH



Similarly, the number of customers participating in VDER CDG as satellites has nearly tripled as seen in Exhibit 2.10-2

EXHIBIT 2.10-22: NYSEG AND RG&E CUSTOMERS ENROLLED IN VDER CDG PROJECTS



Stakeholders need timely and accurate billing that reflects both their usage and the characteristics of their program enrollments. The ability to meet billing requirements as program enrollments increase is crucial to achieving customer satisfaction with the CDG program.

Host Community Benefit Program

The program will provide an annual bill credit to residential electric utility customers with premises located in a renewable Host Community for each of the first ten years that a Major Renewable Energy Facility (greater or equal to 25MW) operates in that Community. The Renewable Owner of a Facility will fund the credits by paying an annual fee of $500 per megawatt ("MW") of nameplate capacity for solar facilities, and $1,000 per MW for wind facilities. The fees paid by the Facility, less utility administrative fees, will be distributed equally among the residential utility customers within the Host Community. The utilities filed Implementation Plans with draft tariff leaves on September 30, 2021, as directed by the *Order*[138] *Adopting A Host Community Benefit Program*, issued on February 11, 2021.[139] As of the date this DSIP was prepared, we currently have no Hosts on this program.

Statewide Solar for All

Solar for All is a New York State utility bill assistance program for income-eligible households the opportunity to take advantage of community solar. The program provides monthly credit for participants assigned to a community solar project. DPS Staff issued a Statewide Solar for All Proposal under Cases 14-M-0224 and 19-E-0735 on May 19, 2023 for public comments.[140] On May 16, 2024, the order came out to start Statewide Solar For All (SSFA) as of December 1, 2024.[141] NYSEG and RG&E must implement a program which allows generation customers that would otherwise be eligible to be a Net Credited CDG Host account to instead be a Statewide Solar For All ("SSFA") Host account. The generation

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[138] Case 20-E-0249 In the Matter of a Renewable Energy Facility Host Community Benefit Program

[139] Case 20-E-0249 In the Matter of a Renewable Energy Facility Host Community Benefit Program issued and effective February 11, 2021

[140] Case 14-M-0224 – Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs. Case 19-E-0735 – Petition of New York State Energy Research and Development Authority Requesting Additional NY-Sun Program Funding and Extension of Program Through 2023. DEPARTMENT OF PUBLIC SERVICE STAFF PROPOSAL ON A STATEWIDE SOLAR FOR ALL PROGRAM Dated May 19, 2023

[141] Case 21-E-0629 - In the Matter of the Advancement of Distributed Solar. Case 19-E-0735 – Petition of New York State Energy Research and Development Authority Requesting Additional NYSun Program Funding and Extension of Program Through 2023. Case 14-M-0224 - Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs. ORDER APPROVING STATEWIDE SOLAR FOR ALL PROGRAM WITH MODIFICATIONS Issued and Effective: May 16, 2024

under both programs is valued based on the Value Stack calculations. Under S-SFA the percentage of the generation value that is not retained by the host or retained by the utility as an administration fee, is placed into an account at the utility. Once a year, the dollar amount in the above-mentioned account is used to create an equal monthly credit to be applied to EAP electric customers that are located in DACs. That credit amount is reconciled and recalculated annually and applied for 12 months beginning December in the same fashion that EAP credits are applied. The percentage of the credit that goes to the EAP in DACs customers will be set for the 25-year VS term but will vary from project to project.

Renewable Access and Community Help program (REACH)

Public Authorities Law (PAL) §1005(27-b) authorizes the NYPA to establish the Renewable Energy Access and Community Help (REACH) program to enable LMI end-use electricity consumers in disadvantaged communities to receive bill credits derived from a portion of the net revenues generated through the production of renewable energy by a renewable energy system planned, designed, developed, financed, constructed, owned, operated, maintained or improved, or contracted for by NYPA as a renewable energy project. As directed by Public Service Law (PSL) §66-p(8), NYPA filed a petition on January 31, 2024, under Case No. 24-E-0084 ("REACH Petition"), to establish the REACH program.
On April 29th, 2024, multiple groups, including the Joint Utilities, filed comments generally in support of the REACH Petition. Following the issuance of the Order Approving Statewide Solar for All ("S-SFA"), NYPA filed reply comments addressing multiple areas that stakeholders commented on including but not limited to alignment of REACH with S-SFA, schedule for REACH implementation, and enrollment and awareness efforts. On October 16th, 2024, the Commission issued the Order Implementing Renewable Energy Access and Community Help Program.[142]

Billing Automation

The Company has successfully automated the various billing methodologies discussed above, with the exception of NC for Phase One NEM volumetric compensation and Remote Credit. No projects in the Companies' service territory are eligible for Phase One NEM monetary crediting.

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[142] CASE 24-E-0084 - Petition of New York Power Authority to Establish the Renewable Energy Access and Community Help Program. ORDER IMPLEMENTING RENEWABLE ENERGY ACCESS AND COMMMUNITY HELP PROGRAM Issued and Effective: October 16, 2024

In addition to these new programs, the Companies have implemented changes to many existing programs. For example, the VDER Transition Order required that excess credits on a subscriber's account remained on that account and could be used by the subscriber, even after the subscriber de-enrolled from the CDG project. Subsequently, this rule evolved such that banked excess credits on a subscriber's account must be returned to the Host's account when a subscriber de-enrolls. This change was made after the JU implemented the initial program requirements. As such, information technology ("IT") and administrative changes were required to multiple programs. Because NYSEG and RG&E has automated these programs, IT updates are required, as well as reporting and data sharing requirements between the Company and the DER provider. In addition, the Company must continuously train its call center staff to understand these changes in order to explain them to customers. The evolution of DER compensation billing is a constantly changing environment that the Company must follow. In addition to DER compensation changes, the Company must assess the impact of these changes on other billing options, such as budget billing and TOU rates. When implementing billing changes to one program, more than just the DER billing program must be analyzed for impacts.

The Company has updated customers' electric bills to show details of the credits they receive each month, the calculation of what was applied to the monthly bill, any excess credits carried over to the next bill period, the fee paid to the CDG Host, if applicable, the name of the CDG project/Host along with contact information. Increased transparency of credit details and calculations leads to a positive customer experience that encourages customers to continue to participate in CDG and support the State's clean energy goals.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2030, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2030 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation; Described where and how plans for topic-related work and investments affect the CGPP; Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

Summary of future Actions

1) Execute plans for developing automated processes and capabilities (e.g., Opt-Out CDG or Multiple Savings Rate) in the Companies' system.
2) Support DER participation in the NYISO wholesale market and prepare for the 2026

FERC Order 2222-compliant model.

3) Continue to promote market growth and DER utilization through tariffs.

4) Continue collaboration with CDG Billing & Crediting WG on key topics including expanding existing programs and further developing the net crediting model.

In addition to existing compensation programs, an additional program – volumetric net crediting – will be implemented as early as year-end 2025, subject to applicable tariffs approved by the Commission. The Companies continue to devote the appropriate time and resources to support each of these programs from design, programming, and implementation to ongoing IT and administrative maintenance. The Companies also devotes substantial work, along with stakeholders, to considering the interaction between these and other non-DER related programs such as time of use and budget billing, as well as opting-in, opting-out, switching, and banking.

In collaboration with the Joint Utilities, NYSEG and RG&E have been working toward automation of the Value Stack billing process since late 2017. This includes the programming of all aspects of Value Stack compensation, including the calculations of each of the Value Stack component for onsite projects, Remote Net Metered (now Remote Crediting) projects, and CDG projects, as well as the details of transferring credits to subscribers and satellites, tracking each Value Stack component in customer banks, and compiling information for both host and satellite accounts.

Future implementation efforts are underway for several different programs. The Companies will support wholesale market developments to address FERC Order 2222. Additionally, the Companies will continue to refine new retail programs, like the Host Community Benefit Program and the new Solar for All Program as well as the new Renewable Access and Community Help program (REACH) giving its customers increased clean energy optionality. Each of these programs are discussed in further detail below.

<u>Wholesale Market Developments</u>

The Joint Utilities have continued to interface with the NYISO as it prepared to launch its DER aggregations market design, which was accepted by FERC in April of 2020. The NYISO launched its aggregations in the wholesale market rules consistent with 2020 FERC approved rules April 15, 2024. NYISO has stated to FERC, and FERC has approved an approach that NYISO will have fully Order 2222 compliant aggregations in the wholesale market in place no later than December 31, 2026. Joint Utilities discussions with the NYISO have centered on the development of processes and hand offs between the NYISO and the utilities in enrolling, assessing, tracking, monitoring, and compensating DER Aggregations participating in the market. Over the course of this discussion with the NYISO, the utilities have continued to evaluate their own corresponding internal processes, including those related to compensation and billing systems administration. The utilities have each implemented the appropriate changes in their internal billing systems' administration and are ready, from a process and technology standpoint, for the NYISO's market launch this year.

The utilities have reviewed and identified tariff changes that will be necessary to enable NYISO's 2023 market launch and its later implementation of a fully FERC Orders 2222 and 841 compliant market. The utilities filed a request with the Commission in September of 2022 requesting approval for these tariff changes. In substance, the changes are meant to preclude dual market participants from receiving duplicative compensation in both wholesale and retail markets concurrently. The NYISO DER & Aggregation participation model allows DERs to provide energy, ancillary services and capacity in the NYISO markets. NYSO was issued 2 deficiency notices in 2023, after responding to those deficiencies, FERC approved the interim market rules on May 15, 2024.

Net Credit for Phase One NEM volumetric compensation

NYSEG and RG&E began offering Net Crediting (also known as CDG Consolidated Billing) for Value Stack customers in April 2021 providing an alternate payment and crediting methodology for CDG Hosts and CDG Satellites that eliminated the need for a separate participation payment from the CDG Satellite to the CDG Host. The program facilitates crediting the CDG Satellite's bills directly for the net credit and then paying the CDG Host the remaining value of the credit, less a utility administrative fee. However, the same program rules do not apply to grandfathered volumetric projects that currently allocate kWh to CDG satellites. On December 20, 2024, the Commission ordered the Joint Utilities to implement a Volumetric Net Crediting program for volumetric community distributed generation projects and fully automate billing within 12 months of the effective date of the Order.[143]

Multiple Savings Rate and Anchor Customers

On May 16, 2024, the Commission ordered the Joint Utilities to implement multiple Community Distributed Generation savings rates and to allow up to three CDG savings rates and the exclusion of multiple anchor customers for CDG projects.[144] In this order the

[143] CASE 19-M-0463 - In the Matter of Consolidated Billing for Distributed Energy Resources. ORDER APPROVING NET CREDITING FOR VOLUMETRIC COMMUNITY DISTRIBUTED GENERATION PROJECTS (Issued and Effective December 20, 2024)

[144] CASE 21-E-0629 - In the Matter of the Advancement of Distributed Solar. ORDER APPROVING MULTIPLE SAVINGS RATES FOR COMMUNITY DISTRIBUTED GENERATION SUBSCRIBERS (issued May 16, 2024)

Commission directed the Joint Utilities to modify their allocation form to allow CDG developers to specify CDG savings rates utilizing fractionalized percentages, up to one decimal place. The Commission adopts the Joint Utilities proposal to allow for the exclusion of multiple anchor customers for a single CDG project. However, the Commission notes that allocations to anchor customers will continue to be limited to up to 40 percent of the total monthly allocations to ensure that mass market customers still receive the majority of the benefits of participating in a community solar project. The Commission directs the Joint Utilities to fully automate the implementation of multiple CDG savings rates and the exclusion of multiple anchor customers from a CDG project within one year of the effective date of this Order (May 12, 2025). Implemented this into automation in our SAP system and were automated by May 16, 2025, as directed.

Statewide Solar For All NY Statewide Solar For All (S-SFA) was ordered on May 16, 2024, by the Commission and is a DG billing program that provides a monthly solar credit for all income-eligible electric customers in the NYSEG and RG&E service territories.[145] Customer eligibility is contingent on specific criteria. For a customer to be enrolled in S-SFA, they must be electricity customers enrolled in the low-income EAP and reside within a DAC) as defined by the NYSERDA. Companies are mandated to begin issuing credits to eligible customers in December 2025[146]. We are currently working on requirements for system enhancements in order to be able to apply credits to these customers. We will be working to build off what is already in place for CDG Net Crediting to automate S-SFA as much as feasible.

Renewable Access and Community Help program (REACH)

The Commission directed implementation of REACH[147]. Similarly to S-SFA, REACH can be viewed as a variation of VS Net Credited CDG. Under REACH, Host credits are then split

[145] Case 21-E-0629 - In the Matter of the Advancement of Distributed Solar. Case 19-E-0735 – Petition of New York State Energy Research and Development Authority Requesting Additional NY-Sun Program Funding and Extension of Program Through 2023. Case 14-M-0224 - Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs, ORDER APPROVING STATEWIDE SOLAR FOR ALL PROGRAM WITH MODIFICATIONS Issued and Effective: May 16, 2024

[146] Case 21-E-0629 - In the Matter of the Advancement of Distributed Solar. Case 19-E-0735 – Petition of New York State Energy Research and Development Authority Requesting Additional NY-Sun Program Funding and Extension of Program Through 2023. Case 14-M-0224 - Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs. ORDER APPROVING STATEWIDE SOLAR FOR ALL PROGRAM WITH MODIFICATIONS Issued and Effective: May 16, 2024

[147] CASE 24-E-0084 - Petition of New York Power Authority to Establish the Renewable Energy Access and Community Help Program. ORDER IMPLEMENTING RENEWABLE ENERGY ACCESS AND COMMMUNITY HELP PROGRAM Issued October 16,2024

between the host, subscribers, and utility based on set percentages. Under REACH, there are no subscribers; the credits are split between the host, the utility, and a designated account or pool which will be used to distributed fixed credits to eligible customers monthly.

As with S-SFA, eligibility for REACH is limited to electricity customers enrolled in the low-income Energy Assistance Program and reside within a DAC as defined by the NYSERDA. The Commission direct utilities, including the Companies, to begin issuing credits to eligible customers in January 2026. Additionally, bill credits for customers enrolled in S-SFA and REACH must be aggregated to one line on the customer's invoice.

Initially, the Companies will bill REACH projects by using existing value stack automation for the small Reach project billing, coupled with some manual processes to allocate value stack into three components: (1) a percentage of the Value Stack credits that goes towards providing bill savings to participating program customers (the Customer Share); (2) a Utility Administrative Fee that the utilities would be permitted to retain; and (3) the remaining portion of the VDER Value Stack credits, paid by the utilities to NYPA or their assigned designee as direct compensation. In 2025, the Companies have started to create program automation, including Reach project billing modifications, billing enhancements for participating Reach customers, reporting, system generated communications.

The exhibit 2.10-3 below highlights our high-level Billing and Compensation Roadmap.**2.10-**

EXHIBIT 2.10-33: BILLING AND COMPENSATION ROADMAP

Capability	Achievements (2021-2023)	Short-Term Initiatives (2024-2025)	Long-Term Initiatives (2026-2030)
CRM&B Billing System Upgrade	• NYSEG and RG&E completed their billing system upgrade in September 2022	• Complete deployment of AMI meters by end of 2025 • SAP / Customer Relationship Management ("CRM") Enhancement Projects in progress	• Full CRM&B Functionality after AMI Deployment
CDG Billing Automation	• NYSEG and RG&E continued progress on CDG Value Stack Billing Automation • Completed Volumetric CDG Billing Automation in 2019	• Implement CDG Value Stack Billing Automation • Conversion of existing Value Stack projects to automation • NEM Phase 1 Automation, • Multiple Savings Rate and Anchor customers	• Additional enhancements to CDG Value Stack and Net Crediting Automation
DER Programs		• EV Charging Stations • Wholesale Value Stack Billing (FERC Order 2222) • Non-Wires Alternatives • SSFA	• Host Community Benefit Program, Remote Crediting,

Capability	Achievements (2021-2023)	Short-Term Initiatives (2024-2025)	Long-Term Initiatives (2026-2030)
		• REACH	

Integrated Implementation Timeline: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2030. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

Please see the exhibit above for more details on the Companies' billing system automation and compensation roadmap.

Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken, or to be taken, to mitigate the risk(s) and/or resolve the issue(s).

The exhibit below highlights key risks and mitigation measures identified.

EXHIBIT 2.10-44 2.10: BILLING AND COMPENSATION RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Complex Billing Changes:** New programs or program requirements involve changes to the billing system. Our legacy systems designed for comparatively simple and straightforward billing based on customer usage often require significant changes or upgrades, and each new change can interact with other recent changes to add complexity.	• The CDG billing development and configuration requires significant updates to all applicable customer service classifications and sub-provisions for the Electric Residential and Non-Residential customers. In addition, there are several special billing provisions including but not limited to: Time-Of-Use rates, Demand Billing, Non-Demand Billing, and Low-Income rates. • Thorough and logical system testing of consumption (net generation and billed consumption), applicable charges and credits calculations, as well as all necessary Bill Print revisions is critical to ensure accuracy to impacted customer bills. • Follow Software Development Life Cycle ("SDLC") – including Requirements, Design documents, Functional Specifications, Integration / User Acceptance Testing, Deployment. • Internal Smoke Testing and Production Validation is completed.
2. **Testing Requirements:** Custom programming requires multiple iterations of testing – each of which needs adequate time to complete – and subsequent changes to billing can require restarting the testing process.	• Multiple Testing Phases are planned and executed: Unit Testing, Technical Unit Testing, Configuration Unit Testing, Functional Unit Testing, Security Unit Testing, Integration Test Cycles, Performance Testing, Parallel Billing Testing, Regression Testing, and User Acceptance Testing.
3. **Manual Shadow Billing:** Manual shadow billing is required until new systems are verified to work as intended. Integrating large numbers of customers and being able to scale quickly for increased rates of adoption prior to the automation process presents additional challenges.	• Production Validation which includes system calculations compared to manual billing spreadsheets to ensure accuracy.

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category's needs will be met over time; Describe and explain the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and *methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.*

The Companies recognize that stakeholder engagement is an important part of customer satisfaction and developing inclusive regulatory policy and to achieve desired policy outcomes. Since the last DSIP filing, the Companies have hosted or participated in many stakeholder engagement sessions to continually provide information to customers and industry participants. This includes past and planned presentations, webinars, and workshops centered on various utility program topics, such as net crediting, value stack compensation, and remote crediting. Collaboration among the Joint Utilities, the NYISO, and stakeholders has been ongoing for the FERC Order 2222 implementation effort.

The Joint Utilities participate in monthly meetings for the CDG Billing and Crediting Working Group, which are predominately attended by DER developers and other industry trade associations (e.g. New York Solar Energy Industries Association(“NYSEIA”) and Coalition for Community Solar Access (‘’CCSA”)), as well as DPA Staff. These meetings are facilitated by NYSERDA and CCSA. In late 2022 and early 2023 the Joint Utilities also participated in multiple stakeholder conference on CDG billing and crediting issues hosted by the Commission where industry stakeholders proposed performance metrics and negative revenue adjustments (NRAs).to be tied directly to the utilities’ CDG crediting and billing performance. In January 2021, DPS Staff filed a proposal outlining CDG billing and crediting metrics with NRAs, which was countered with a simpler alternate proposal by the JU. The outcome is still outstanding pending a Commission Order.

Additional Detail

A monthly bill is often the only method of engagement and communication between a utility and its customers. Because of this, customer billing and compensation are vital components of a utility's core business and, therefore, must be accurate, timely, and transparent. It is DPS Staff's position that billing that is consistent, accurate, and well explained will lead to increased customer satisfaction and reduced inquiries to the utility's call center and/or reduced customer complaints to the Commission, on social media, or to the press.

1) *Along with satisfying the general guidelines for information related to each topic (see Section 3.1), DPS Staff recommends that the DSIP Update should provide the following additional details pertaining to customer billing and compensation: Describe the various DERs-related billing and compensation programs (including demand response) implemented or revised by the utility since the last update. For this first inclusion in the DSIP, describe developments that have occurred since the beginning of NEM, Reference Network Model ("RNM"), CDG, and VDER.*

The Companies have implemented and automated numerous DER-related programs since NEM began in 2015. Grandfather NEM, Phase 1 Volumetric CDG and other pre-VDER programs have been automated in the CRM system for some time, The most recent effort was to automate the VDER Value Stack CDG program as described below. Below is a detailed table discussing the various workstreams of the VDER Value Stack automation project.

EXHIBIT 2.10-55: DER-RELATED BILLING AND COMPENSATION PROGRAM CHANGES

Workstream Nos.	Programming Changes	Deployment
1	Satellite Relationships; Add, update and remove relationship through batch process; programming of exemptions and automatic removal of satellite when removed from the host relationship	1/1/2024 (completed)
2	Billing of Value Stack CDG Phase 1 and Phase 2 projects with satellite transfers; Billing of Value Stack Net Crediting Phase 1 and Phase 2 projects with satellite transfers	1/1/2024 (completed)
3	Value Stack CDG host bank distributions; Value Stack CDG host bill cancel/rebill; Value Stack CDG reporting (e.g. Host Summary Report, Applied Credit Report)	1/1/2024 (completed)
4	Value Stack CDG Multiple Savings Rate and Anchor customer; programming changes to allow multiple savings rate and anchor customers	May 16, 2025 (completed)

For Demand Response, there have been a few updates to its' programs for compensation. Regarding our Smart Savings Rewards program, the Companies had increased its up-front DR rebate amount for purchasing a thermostat from $45 to $70. This increase allows customers a broader range of options in participation in the Smart Savings Rewards program and in some cases, they can receive a free thermostat. The participation credit for customers is unchanged. In late 2024, Companies' Auto-/Term-DLM program procurement methodology was modified from a seal, pay-as bid to a fixed price procurement. In each RFP, the Companies will provide the fixed price amount for NYSEG and RG&E which will allow customers to better understand the benefits they can receive from their participation in the programs. Finally, the Companies are introducing a new DR program called NYSEG and RG&E Energy Storage Solutions (ESS). Customers who enroll in the program can performance compensation of $50 per average kW of the season.

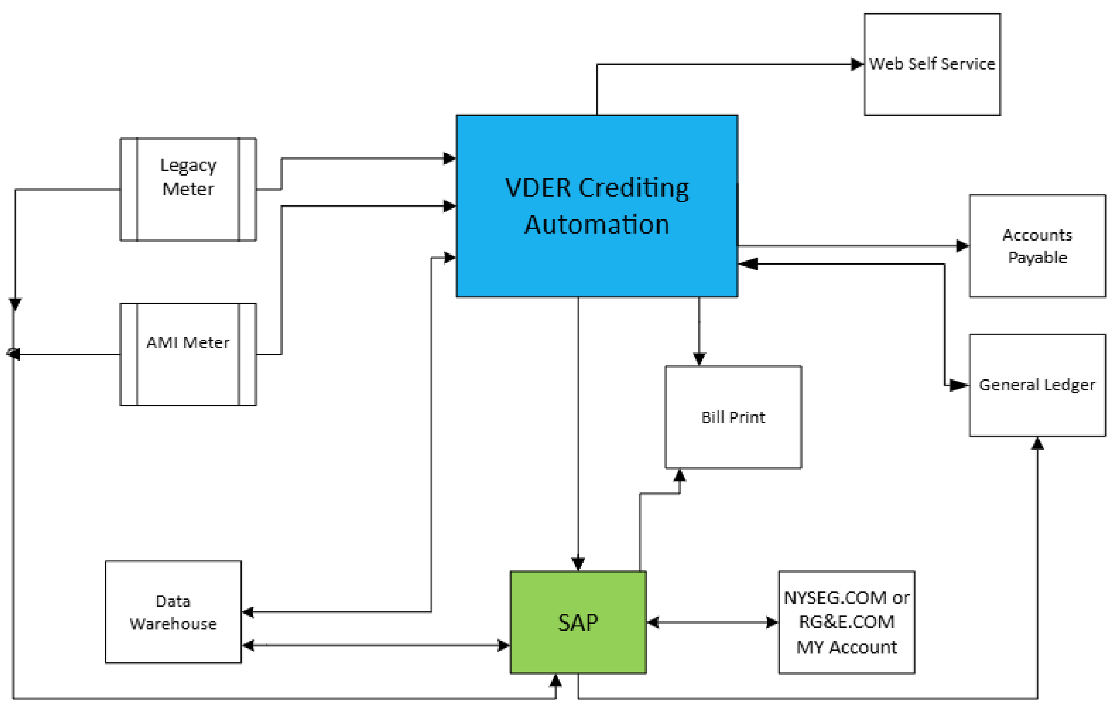
EXHIBIT 2.10-66: PROGRAM CHANGES

Program	Changes	Implementation
Smart Savings Rewards	Increased DR rebate amount	Spring 2023
Auto-/Term- DLM	Modified procurement methodology	December 2024
NYSEG and RG&E ESS	Addition of new program	Summer 2025

2) *Describe the customer billing/compensation functions and data generally needed to expand deployment and use of DERs in the utility's service area. Include descriptions of the existing and planned components (processes, resources, and data exchanges) that will support those needs. For planned components, provide the sequence and timing of key investments and activities required for component implementation.*

The customer billing functions that NYSEG and RG&E use for billing and compensation of its DER programs include billing and crediting, program management, call center support, billing analysts, accounting, rate engineering, data sharing and reporting. Specific data needs to vary depending on program but generally includes meter data from both AMI data repositories as well as Interval Meter Data, account information from CRM, DER information from Interconnection portal and financial data. Additionally, specific data needs from NYSIO and NYSERDA managed systems focus on the reporting and synchronization of customer registration. A simplified view of the VDER system billing and data sets is shown below in Exhibit 2.10-7

EXHIBIT 2.10-77: VDER SYSTEM BILLING AND DATA SETS



For Demand Response programs, there are a couple data sources needed to expand deployment. On the Residential side, the need for thermostat runtime data as well as battery telemetry data is needed. NYSEG and RG&E would also need the DERMS vendor data that includes OEM data and detailed event performance data. On the C&I side, interval meter data is critical in calculating event performance, event baseline, and customer performance incentives. The use of account information from CRM is needed to validate customer enrollments. In the near future, AMI data will be replacing the interval meter requirement. For grid optimization, a customers DER type, size, location, output, and typical usage patterns will be used for targeted load relief for distribution needs.

3) *Describe the customer billing/compensation functions and data needed to enable DER participation in the NYISO's wholesale markets for energy, capacity, and ancillary services. This should include information regarding the utility's implementation of its Wholesale Distribution Service (WDS), Wholesale Value*

Stack (WVS), and related non-wholesale value stack (VDER without wholesale energy and capacity components). Also include descriptions of the existing and planned components (processes, resources, and data exchanges) that will support those needs. For planned components, provide the sequence and timing of key investments and activities required for component implementation.

The Companies are evaluating the functionality needed to enable DER participation in NYISO's wholesale market for energy, capacity, and ancillary services. The billing system must be updated to credit customers participating in this market appropriately by excluding the energy and capacity components of VS compensation. The Companies are developing processes and systems to accept customer-participant information, which will include account numbers at a minimum. The billing system must be updated to identify participating customers and apply the appropriate rate code and/or indicator for proper charging and crediting. In addition, bill presentation must be updated to include sufficient information to provide a positive customer experience. A process to transfer information between the Companies and the DER Aggregator, who may not be a customer of the Companies, must be developed. The Companies anticipate that it will have the ability to bill participating customers when wholesale market participation begins. The timing of system updates is unknown at this time.

4) *Describe the utility's plans to implement or modify DER-related billing and compensation capabilities, including automation, to address the Community Distributed Generation (CDG) billing and crediting problems that were the focus of the Commission's September 15, 2022, Order in Cases 19-M-0463, et. al.*[148]

As detailed above, NYSEG and RG&E filed its Implementation Plan on October 14, 2022 on billing system constraints preventing full CDG billing automation, billing system changes necessary to effectuate automated CDG billing, and the steps and timeline to achieve full automation of CDG billing pursuant to Ordering Clause 2 of the Commission's September 15, 2022 in Case 19-M-0463. NYSEG and RG&E Automated the VDER CDG program as of January 1, 2024. We are currently working on new orders that came out late 2024 and need to be automated Q1 2025 and Q4 2025.

5) *For each type of DER billing and compensation, including for CDG and wholesale market participation, describe the current information system constraints preventing full automation of DER billing and compensation.*

[148] Case 19-M-0463, In the Matter of Consolidated Billing for Distributed Energy Resources, Order Establishing Process Regarding Community Distributed Generation Billing (filed September 15, 2022).

The duration of time it takes to implement full automation is primarily related to the complexity associated with the program and interactions with variations of billing options within our existing customer billing structure. Each billing option (including but not limited to Service Class, Supplier Choice, Demand Billed, Non-Demand Billed, Time-of-Use Rates, Hourly-Priced Rates, Low Income Provisions, NYPA Power allocations, Budget Billing, Installment Plans, Taxes, etc.) requires a separate review and development work, if impacted, to ensure the CDG billing methodology produces the required end result of billing and crediting to the impacted customers. The process includes Regression Testing of scenarios with customers not enrolled in the program to ensure their billing is not impacted by the changes.

The CDG Program required consideration and development of functionality, programming, and management in a number of areas. This included (but was not limited to) Information/Data Storage about the project and its Satellites and how such information is presented to stakeholders across the company, the File Exchange processes with Hosts, Host Metering, Host Billing, Distribution of Compensation to Satellites, Distribution of Phase 1 Components with additional complexity (Demand Reduction Value, Market Transition Credit, and Non-Mass Market Community Credit), Bill Presentment, Host Move-Outs, Satellite Drops, Satellites enrolled with Multiple Hosts, Reporting Needs (both internal and external), and consideration of Net Crediting across all the previously discussed considerations.

6) *Describe how DER billing and compensation affects other programs such as budget billing, time of use rates, and consolidated billing for ESCOs.*

Time of use rates: Customers on time of use rates are eligible to participate in all DER NYSEG and RG&E tariffed programs. Compensation may vary by consumption time-period as outlined in NYSEG and RG&E tariffs.

Budget billing: Budget billed customers are eligible to participate in all DER NYSEG and RG&E tariffed programs. For on-site generation programs where the billed consumption is net consumption and for CDG volumetric satellites, the customer's budget installments are adjusted through the quarterly review process based on historical billed amounts and remaining months to the customer's budget true-up. For the remaining programs where compensation is given through a monetary credit, the credit is not reflected in the customer's budget amount. The credit reduces the amount the customer owes which includes the customer's billed installment amount.

Energy Service Company ("ESCO") consolidated billing: Customers on consolidated billing are eligible to participate in all DERs NYSEG and RG&E tariffed programs. Under

NYSEG and RG&E's utility consolidated billing program, NYSEG and RG&E provide billed consumption to the ESCOs. ESCO's calculate the supply charges for the customer and provide the supply charge to NYSEG and RG&E for inclusion on the customer's utility bill. NYSEG and RG&E provide ESCO's with the customer's net billed consumption for DER programs where customers are billed on net consumption.

7) *Describe the utility's means and methods - existing and planned – for monitoring and testing new or modified customer billing and compensation functions.*

The Companies' Business Support & Solutions Department and internal IT Department maintain a standard process for testing system changes. Due to the complexity of the CDG code, thorough testing of all functionality is required. User Acceptance Testing, Volume Testing, Integration Testing, and testing with a thrid party Project are all part of the process. In addition, Regression Testing is necessary to ensure no impact to other areas of billing or bill-print. Regression testing is also required when initial testing defects are discovered and then fixed by a change to existing code. This occurs throughout the entire cycle of programming changes. Upon implementation, production validation and monitoring of changes for all functionality will occur, including a comprehensive review of every production scenario, as well as bill validation for customers not enrolled in the program.

8) *Describe the utility's means and methods – existing and planned - for supporting customer outreach and education, including where and how customers, DER developers/operators and other third-parties can readily access information on the utility's billing and compensation procedures.*

As previously discussed, the Companies participates in many stakeholders engagement sessions with customers and industry participants. The Companies plan to continue to participate in such engagement sessions including webinars, workshops and working group sessions. In addition, the Companies have a dedicated DER team that manages relationships with DER developers/operators and acts as a point of contact for these projects. The Companies also mantain a section on our websites for customers, DER developers/operators and third parties. The websites provide detailed information for customers and developers on programs available to them and the applicable program rules. In addition, the Companies did offer small group training sessions on understanding the new CDG Allocation forms and host reports that will launched in Janurary 2024. A presentation was made on these Allocation Forms and reports at the

April 15, 2024 CDG Billing & Crediting Working Group meeting. We offered meetings in April 2025 as to the changes that we are making to the Allocation form and reports due to the Multiple Savings Rate and Anchor customer changes that was implemented on May 12, 2025. The Companies are also currently doing pop up events in multiple locations in order for customers to come ask questions about DER programs or billing information.

9) *Describe the utility's means and methods - existing and planned – for receiving, investigating, and monitoring customer complaints and/or inquiries regarding billing and compensation issues related to DERs.*

The Companies will continue to follow existing business practices related to receiving, investigating, and monitoring customer complaints and/or inquiries regarding billing and compensation issues related to DERs. All customers who filed complaints will be attempted to be contacted by phone and/or email within 24 hours of receiving their complaint, to acknowledge receipt of their complaint and possibly resolve the complaint. A thorough investigation will be conducted and adjustments to customers' accounts will be completed as appropriate. Service recovery steps identified by Companies will be followed to de-escalate the customer's concern. If the customer is still unsatisfied with the Companies' resolution, a written formal response is sent to the customer of record as required by the Commission.

2.11 DER Interconnections

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2023 DSIP Update filing.

Since the 2023 DSIP filing, the Companies continued to process interconnecting DERs within the required timelines specified in the NYSSIR.

Since the 2023 DSIP, NYSEG/RG&E have continued to see a high volume of large applications. Exhibit 2.11-1 below illustrates the total number of interconnection applications that the Companies have received under the NYSSIR for system sizes between 0MW and 5MW from 2019 - 2025. Mostly in the NYSEG territory.

EXHIBIT 2.11-1: 2INTERCONNECTIONS APPLICATIONS NYSEG & RG&E

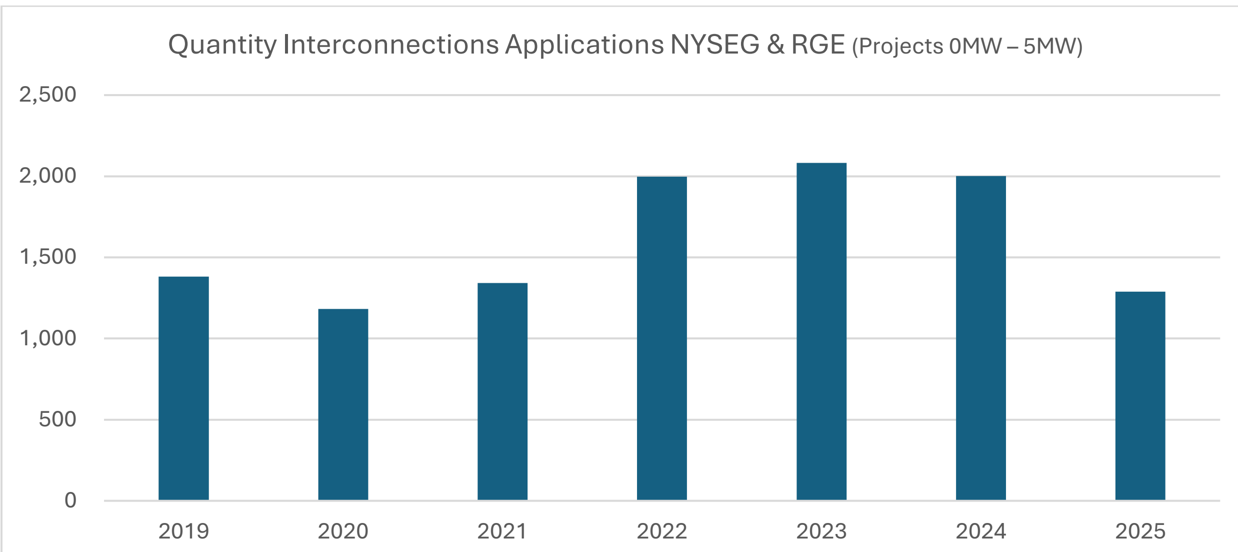
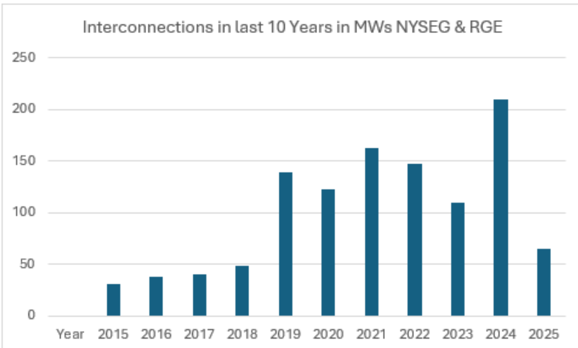
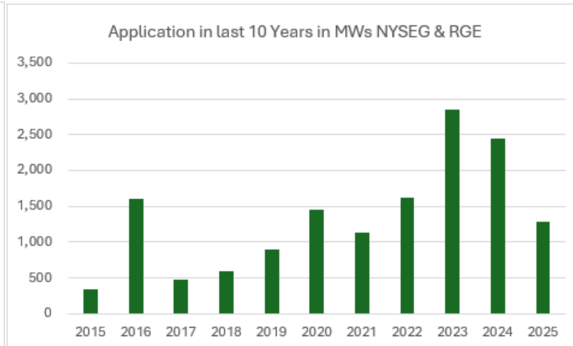


Exhibit 2.11-2 below illustrates the number of interconnections and application requests in MWs received over the last ten years. Prior to 2022, the Companies processed approximately 6,592 MWs of proposals; from 2023 to present, the Companies have experienced approximately 7,311 MWs of interconnection requests. Approximately 1,034 MW of projects are in various stages of activity.

EXHIBIT 2.11-2: THE NUMBER OF INTERCONNECTION AND APPLICATION REQUESTS IN MW RECEIVED OVER THE LAST TEN YEARS.





· Updated policies, processes & standards to comply with the Cost Share 2.0.

· Updated policies, processes & standard to comply with IEEE 1547 requirements/Underwriters Laboratories (UL) 1741 Supplement B (SB).

· Updated the DER technical guidance/requirements for IEEE 1547 requirements/UL 1741 SB.

· Progressed update of Bulletin 86-01 Interconnection Requirements.

· Complied with industry requests to provide periodic updates to the Interconnection Cost Matrix to provide developers with insight into relevant costs associated with interconnection of DER.

· Established procedures to comply with CASE 24-E-0414 letters of credit (LOCs) with policies, processes & standards.

· Updated policies, processes & standards for the new metering options Renewable Energy Access and Community Help (REACH), Statewide Solar for All (S-SFA) & RNM.

· Posting Capital Investment Plan, Capital Queue, Encumbered substation list & MVD list on Company web pages.

· Added resources - contractors and internal project manager FTE.

· Working to enhance database to include additional data points to comply with industry requests for data.

Current Progress: Describe the current implementation as of June 30, 2025; describe how the current implementation supports stakeholders' current and future needs.

NYSEG and RG&E added one additional internal resource as well as two contractors to provide a better developer experience. Additional support will help in the CESIR reporting efforts as well as bringing projects to fruition. The process includes personnel who collaborate with developers as they navigate through the interconnection process. The following are some efforts provided to developers: ad hoc/set scheduled meetings to discuss next steps in the process, provide guidance, and review independent construction schedules so Companies and developer's timelines come together for inspection, energization, and testing after construction is complete. It is important that the Companies communicate consistently work efforts with developers to ensure projected completion date(s) to manage external stakeholder expectations and to forecast accurately. The Companies are proposing to add two Senior Analysts and one Manager – Programs/Projects in their 2025 rate case. These additional FTEs will enable the Company to manage the increasing volume of applications and projects moving into execution.

The Companies also participate in the Joint Utilities' ITWG and IPWG, and have made considerable progress in the following areas:

CESIR Study Process Reexamination: The JU collaborated with members of Industry on a "Comprehensive CESIR Analysis Evaluation Initiative" to help developers better understand how interconnection applications are being studied in the CESIR process. The JU provided detailed responses to Industry on study methods for certain screens within the CESIR: Overvoltage, Undervoltage, Voltage Regulator Correction Capability on Feeders and Substations, Excessive Regulator Movements, and Voltage Flicker. This initiative led to the JU providing detailed data publicly on the number of new DER projects passing or failing the CESIR process on an annual basis, as well as a re-examination of the voltage flicker calculation (CESIR Screen H).

As mentioned previously, the JU collaborated with EPRI, Pterra Consulting and Industry to amend the voltage flicker calculation (Screen H) in the CESIR. This amendment went into effect on April 1, 2022. The amendment is anticipated to result in an increase in projects passing the CESIR Screen H.

Storage Metering Guidelines: The JU developed and proposed storage metering architectures for various technology configurations (storage exclusively charged by DG, storage unable to export to the grid, any charging and exporting configuration with netting) to serve as a guide for developers. The goal of the publication of this document was to give developers a better sense of the metering configurations that could be used for their projects.

Grounding Practices: The JU collaborated with EPRI to make noteworthy progress on understanding effective grounding practices and policies for DERs. The effort helped inform and improve the JU's interconnection study capabilities and safety measures. The collaboration also resulted in the publication of a report, thus contributing and adding to the existing body of knowledge on this topic.

Voltage Regulation: The JU created a joint "Voltage Regulator Subgroup" with Industry to help stakeholders better understand how pole-mounted regulator tap operations are affected by PV interconnection, which in turn has implications for CESIR study screens and regulator lifetimes. As part of this initiative, the subgroup surveyed commercially available regulators and utility data to understand regulator lifetimes and the number of possible tap movements in the presence of DERs.

Bulk Power System Support and Smart Inverter Settings: The JU developed and released bulk power system support and voltage support settings/ setpoints for smart inverters, as part of the Phase 1 activity of the Companies' joint Smart Inverter Roadmap. The release of these settings was timed to align with the commercial availability of IEEE 1547-2018 compliant and UL 1741- SB certified inverters. To develop the settings, the JU collaborated extensively with NYISO, peer utilities, and members of industry. Consequently, the JU members incorporated the inverter setpoints into their respective technical interconnection documents. The JU also provided DPS and Industry with a document containing web links to each company's documentation. The JU also created a smart inverter FAQ document for non – technical audiences. In collaboration with the IPWG, New York DPS, and Industry, the JU updated the SIR document to reflect the outcomes of ongoing discussions, including items related to the use of smart inverters.

DER Technical Guidance: The JU updated the DER technical guidance/ requirement matrix and the cost matrix to provide up to date information for developers. Both matrices provide indicative estimates of various scopes of work and the relevant costs associated with the interconnection of DERs on an individual company basis.

Inverter Settings: In collaboration with EPRI and Industry, the JU is currently investigating the implementation and enforcement of a standard file settings format to share inverter settings. EPRI demonstrated the details of the inverter settings sharing format with the ITWG, as well as separately to the JU. Using this file format will create consistency and standard approaches to inverter settings file creation, verification, and implementation.

As a result of this collaboration the JU have engaged EPRI to aid in developing standard inverter settings files for each individual utility within the JU.

As mentioned previously, the JU have made considerable progress in the following areas:

Incorporating smart inverters, which offer the benefit of several advanced functions and could potentially be used as a low – cost monitoring and control solution.

Additionally, the use of standardized file sharing formats such as the EPRI CFF is anticipated to reduce the time required for utility engineers to study inverter settings, which will in turn improve interconnection application processing times.

Extending the timeline for requirement of UL 1741 SB certified bi-directional EV chargers, thus staying aware of certification timelines, and demonstrating collaboration with EVSE manufacturers.

Through the UL 1741 CRD for Multimode effort, remaining cognizant of technical standard development activities and new DER architectures.

Making edits to the SIR, which is anticipated to lead to a greater volume of interconnected DERs.

Establishing the storage charge and discharge schedules, which will help developers maximize the economic value that BESS assets can accrue.

Providing developers with the latest information via refreshes of the interconnection cost matrices.

Providing developers visibility and transparency into utility processes for estimating and reconciling the costs of distribution system upgrades identified in CESIR studies.

These implementation efforts support stakeholder needs and state clean energy goals by resulting in increased efficiency in the interconnection application and study processes, which in turn result in increased volumes of DER interconnections.

These implementation efforts support stakeholder needs and state clean energy goals by resulting in increased efficiency in the interconnection application and study processes, which in turn result in increased volumes of DER interconnections. The development of low-cost monitoring and control solutions for DER results in economic benefits to developers.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2030, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2030 and beyond; Identify and characterize the work and investments needed to progress from the current *implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation; Described where and how plans for topic-related work and investments affect the CGPP Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.*

The Companies will continue to make progress on Phase 2 automation over the near term as well as Phase 3 automation over the long term. We are currently working to transition over to a web base database and enhancement to the visual aid of the status of a project as it moves through the interconnection process.

The company is looking into the future with phase II of the flexible interconnection program. Currently phase II status is that we have submittal a proposal and are waiting for DPS to provide further direction on how to proceed. We are targeting deployment of a total of 7 total flexible schemes by the end of 2028. There is significant work involved in both the policy and technical side. This includes investments in changes to the NYSSIR in contractual obligations and study requirements. There are continuous conversations on flexible interconnections as part of the ITWG and IPWG and will require continued efforts to support stakeholders' needs in 2030 and beyond.

The Companies presented to DPS and Industry on their ongoing initiatives related to flexible interconnection of DERs phase II. The JU will continue with their internal initiatives and share lessons learned with DPS and Industry in 2030 and beyond.

Future implementation efforts support stakeholder needs and state clean energy goals by resulting in increased efficiency in the interconnection application and study processes, which in turn result in increased volumes of DER interconnections. The development of low –cost monitoring and control solutions for DER results in economic benefits to developers. Future implementation of smart inverters functionality is anticipated to provide additional flexibility and higher integration of DERs. NYSEG and RG&E offered a pilot flexible interconnection and is looking into the future with phase II of the program. There is significant work involved in both the policy and technical side. This includes investments in changes to the NYSSIR in contractual obligations and study requirements. There are continuous conversations on flexible interconnections as part of the ITWG and IPWG and will require continued efforts over the next few years.

The JU, along with Industry and DPS Staff, continue to collaborate on activities related to flexible interconnection schemes for DER.

NYSEG and RG&E and National Grid have presented to DPS and Industry their ongoing initiatives related to flexible interconnection of DER.

Several of the JU members are engaged in pilot projects or are making other foundational investments to establish the building blocks for greater control of DERs, including flexible interconnection. The JU will continue with their internal initiatives and also share lessons learned with DPS and Industry in 2025 and beyond.

These initiatives are anticipated to increase the amount of DER that can be connected to circuits and also allow developers to access diverse revenue streams and use cases.

The JU are working with EPRI and stakeholders to implement the adoption of the EPRI CFF for sharing smart inverter settings.

The JU believe that both the utilities and developers will benefit if manufacturers were to adopt the CFF, since this would lead to quicker verification of inverter settings and reduced person-hours per project, which will in turn shorten interconnection timelines.

This has already been observed by a few utilities in NY who have successfully worked with several inverter manufacturers to create inverter grid codes for their respective companies.

Moving forward, the JU will collaborate with Industry to jointly approach inverter manufacturers to implement the CFF functionality.

Following up on these conversations, the JU are intending to implement a requirement for the EPRI CFF implementation by January 1, 2026.

EXHIBIT 2.11-3: DER INTERCONNECTIONS ROADMAP

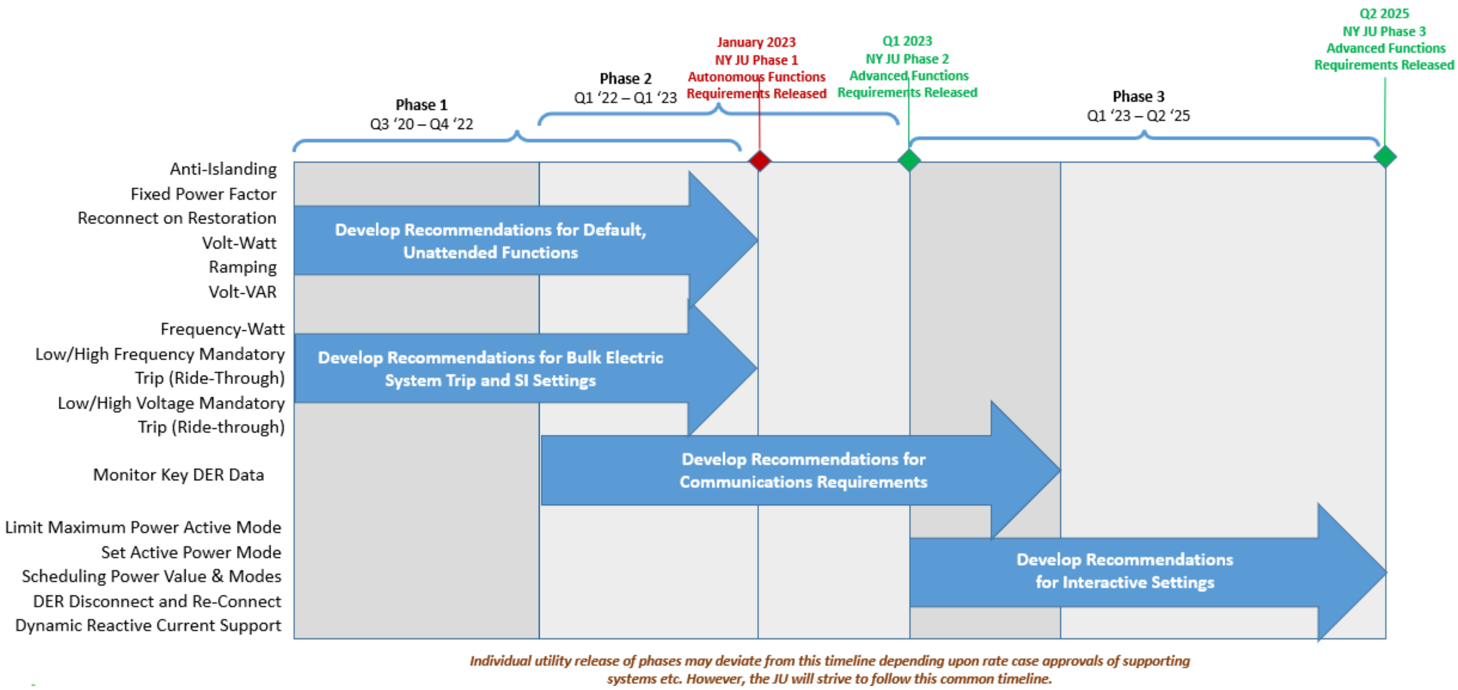
Capability	Achievements (2023-2025)	Short-Term Initiatives (2026-2027)	Long-Term Initiatives (2028-2030)
Flexible Interconnection	• Demonstrate Flexible Interconnection Use Case (FICS REV Demo Phase 1)	• Expand deployment of Flexible Interconnections to additional grid locations • Expand deployment of Flexible Interconnection to Electric Vehicle Charging	• Procure Flexibility services based on forecasted and real-time grid needs

<u>Integrated Implementation Timeline</u>: Using a generic format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period

ending in 2028. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

The exhibit below highlights the Joint Utilities' integrated implementation timeline.

EXHIBIT 2.11-4: DER INTERCONNECTIONS INTEGRATED IMPLEMENTATION TIMELINE



<u>Risks and Mitigation</u>: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E have identified three risks that relate to performance of the interconnection process, and have taken measures to mitigate each risk, as shown in the exhibit below.

EXHIBIT 2.11-5: DER INTERCONNECTION RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Data:** DSO performance will depend on the quality of data that is relied upon by the DSO to perform special interconnection studies	• NYSEG and RG&E are designing the GMEP and related data efforts to incorporate governance and data processes and flows • Performing a data governance/data quality pilot roadmap for DER integration • Maintain an updated Interconnection DER database • Resolving data conflicts and accuracy as part of IEDR effort.
2. **Large Volume of Interconnection Requests:** the DSO must meet the SIR requirements	• Efforts to automate data flows and other aspects of the interconnection process to the extent possible • Daily "green/yellow/red" reports on interconnection status to internal functions that contribute to interconnections and a company officer. • Use of contract resources to supplement internal engineering staff for interconnection studies. • Added resources - contractors and internal project manager Full Time Employee (FTE) to handle increase volume
3. **IT Resources:** procuring IT resources on short notice to implement required regulatory changes to the Interconnection Online Application Portal ("IOAP") per SIR changes	• The Companies complete documents each year to alert IT to specific business needs. • The Companies have one full-time equivalent ("FTE") IT resource on staff to manage activities.
4. **Energy Storage Integration:** As the type and number of energy storage use cases that the JU is required to study in CESIR process increases, the complexity of the CESIR study process may increase.	• The JU may need to develop new procedures to verify ESS settings, control schemes and ensure that these are appropriately documented. • The JU will continue to stay in touch with each other and DPS, Industry, and other stakeholders to proactively identify and address issues.

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category's needs will be met over time; Describe and explain the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

As DER penetration rises it is necessary for the JU to maintain interconnection processes that are accurate, consistent, and efficient.

Maintaining these qualities becomes challenging as the volume and complexity of projects increases, and the ability to connect DERs quickly, safely, and reliably relies on the JU's processes and ability to identify technology alternatives.

Significant process gaps and/or limitations in available technology could impact the JU's ability to integrate larger volumes of increasingly complex DERs in a timely manner.

The JU is mitigating these risks by continuously identifying opportunities for process improvements and working with NYSERDA, other utilities across the US, and industry organizations such as UL and EPRI to assess innovative technologies and verify operational concepts.

The Interconnection process has been and continues to be an important topical area for stakeholder collaboration through Joint Utilities. The ITWG promotes consistent standards across the utilities to address technical concerns affecting the distributed generation community that relate to interconnection procedures. The IPWG explores non-technical issues related to the processes and policies relevant to the interconnection in New York. Additionally, each utility has a DG Ombudsperson to whom developers can raise concerns. DG Ombudsperson list can be found HERE. Interconnection Ombudsman Effort | Department of Public Service

We participate in the ITWG and IPWG to coordinate with the Joint Utilities on interconnection issues. Participation in these working groups allows us to identify and assess changes to the SIR and develop technical guidance in response to stakeholder concerns. We will collaborate with the Joint Utilities to reduce barriers to entry of all DER types and working with Staff and stakeholders to provide greater predictability of interconnection costs to the customer.

The IPWG and ITWG have each met regularly over the past two years to address a range of interconnection issues, focusing on storage integration, low-cost monitor and control technologies (e.g., smart inverters), voltage flicker issues, and technical screen changes.

The JU has engaged stakeholders on DER interconnection processes through the public monthly ITWG meetings, as well as through individual utility – developer interactions. These meetings have served a key role since 2016, acting as a forum for the resolution of technical issues related to DER interconnection.

In future, stakeholder engagement will continue through the monthly ITWG meetings that are open to the public. Key stakeholders participating in these meetings include the JU, DPS Staff and Industry members - project developers, trade groups and associations, technical consultants, and equipment manufacturers.

These forums provide an opportunity for Industry members to raise and discuss any technical issues that they are facing pertinent to DER interconnection. The meetings also allow DPS Staff to identify topics of interest and areas of prioritization in the near and long term.

Meeting agendas and supporting materials are posted online to the DPS' ITWG website prior to the meeting and are available for download.

In addition, the JU lead for the ITWG will continue to meet on a regular basis with DPS Staff and the Industry group's liaison. This activity helps to set the agenda for the monthly, public meetings, identify new topics for discussion, identify any issues as they arise, and ways to address these issues. The JU will also continue to update the technical documentation on the ITWG website, to ensure that stakeholders and project developers are provided with the latest information. As the JU progresses in its efforts to integrate increasing quantities of DERs, the JU will seek to continue to receive information from Industry regarding specific pain points and justification for new requests.

Each utility has a DG Ombudsperson to whom developers can raise concerns.

Additional Detail

Implementing the utility resources and capabilities that enable DER interconnections to the distribution system are a critical early objective. Many of the details which identify and characterize those resources and capabilities are being worked out by the ("ITWG") and *the ("IPWG") which are stakeholder collaboratives led jointly by Staff NYSERDA. The goal of both working groups is to establish the requirements for standard resources, processes, specifications, and policies which foster efficient, timely, safe, and reliable DER interconnections.*

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to DER interconnections:

1. *Describe in detail (including the web URL) the web portal that provides efficient and timely support for DER developers' interconnection applications.*

The NYSEG Distributed Generation website can be accessed NYSEG here and RG&E here. The instructions on use of the NYSEG/RG&E online application portal are available here.

NYSEG and RG&E hosting capacity portal is available here.

Provides greater transparency into the ability of a distribution grid to host additional DERs. In addition, hosting capacity maps can identify where DERs can alleviate or aggravate grid constraints. Utilities, developers, and other stakeholders can use hosting capacity maps for better planning and assist companies to identify where there is available capacity on the electric grid to connect new projects.While hosting capacity maps do not address site-specific interconnection questions, they can provide a general understanding of a specific network's capacity to accommodate new DERs.

NYSEG Interconnection Project Queue – here

Provides greater transparency where every project is within the life cycle of the project providing information like circuit ID, queue postion, project number, developer, project size, application accepted, PSA received date, CESIR funding received, CESIR commence date, CESIR review complete date, Initial construction funding received date, full construction funding received date, meter type

SIR Inventory Information - here

Provides project spefic information like developer, City, County, NYISO load zone, Circuit ID, Subsation, System size and type, meter type, value stack, application review dates, PSA dates, CESIR dates, project upgrade costs, construction payments/dates

Encumbered Distributed Generation Queue Locations – here (bottom of page)

Provides a list of substation that have distributed generation queued in excess of the transmission system's capability to support

2. *Describe where, how, and when the utility will implement and maintain a resource where DER developers and other stakeholders with appropriate access controls can readily access, navigate, view, sort, filter, and download up-to-date information about all DER interconnections in the utility's system. The resource should provide the following information for each DER interconnection:*

The interconnection inventory report queue for each utility is available online. The interconnection inventory report is updated monthly on the DPS web site here. The Companies' hosting capacity is available online here. The hosting capacity menus include the number of connected DERs and interconnection requests in the queue. Currently, hosting capacity maps are updated less frequently than the interconnection database. Thus, developers must compare hosting capacity maps to our monthly PSC-mandated queue data submittal. The Company also have available online a Queue Order by Substation report that is updated monthly NYSEG here, RG&E here.

Those DER facilities with Mechanical Completion are integrated into NYSEG/RG&E's Energy Management System (EMS) to enable the Company to remotely trip the generation, or DER facility, from the Companies' Electric Power System (EPS) if necessary to maintain reliability.

a. *DER type, size, and location;*

The DER type, size, and location can be found in the SIR inventory report.

b. *DER developer;*

The developer is identified. The owner-operator or operator is not identified, as this is considered confidential customer information according to Commission guidelines.

c. *DER owner;*

The owner-operator or operator is not currently identified, as this is considered confidential customer information according to PSC guidelines.

d. *DER operator;*

The DER operator is not currently identified, as this is considered confidential customer information according to PSC guidelines.

e. the connected substation, circuit, phase, and tap;

The substation and circuit are identified. The phase and tap are not included in the reported information, although it would be possible to identify the phase based on the circuit location. We can also add a GIS ID in response to the request for "tap" identification if the value to developers exceeds the costs to provide it.

f. the DER's remote monitoring, measurement, and control capabilities.

This information is not currently publicly available. Installation less than 500kW may not require SCADA Data. Installations greater than 500 kW have a point-of-connection recloser. Installations greater than 500 kW are subject to monitoring and control via SCADA communication module installed on reclosers. Control is generally an on/off feature; we are generally not able to dispatch the resource. Some installations may have smart inverters that are available for voltage control.

All "Value-of-DERs" compensated installations require phone lines for remote interrogation of the meters. Other communication media may be acceptable in lieu of a phone line.

g. the DER's primary and secondary (where applicable) purpose(s); and

This information is not currently publicly available and will only be made publicly available if requested by the PSC.

h. the DER's current interconnection status (operational, construction in-progress, construction scheduled, or interconnection requested) and its actual/planned in-service date.

The interconnection queue and Queue Order by Substation report (URL found above) includes an overall status of "In Queue," "Interconnected," "Cancelled," or "Full Funding Received," as well as the following additional information related to interconnection status:

- The actual in-service date can be found within the SIR inventory report using column "Final Letter of Acceptance Date." We do not currently post the planned in-service date and will only be made publicly available if requested by the PSC if known.
- Substation Location
- Circuit ID

- Project Number
- Queue Position
- Application Received
- Application Accepted
- Date Completed Preliminary Screening
- The preliminary screens requiring automation in Phase 2, referred to as screens A through F, are as follows:
    - Screen A: Is the PCC on a Networked Secondary System?
    - Screen B: Is Certified Equipment Used?
    - Screen C: Is the EPS Rating Exceeded?
    - Screen D: Is the Line Configuration Compatible with the Interconnection Type?
    - Screen E: Simplified Penetration Test
    - Screen F: Is Feeder Capacity Adequate for Individual and Aggregate DER?
- Date CESIR Funding Received.
- CESIR Commence Date.
- CESIR Final Technical Review Completion Date.
- Technical Screens G through I are as follows:
    - Screen G: Supplemental Penetration Test
    - Screen H: Voltage Flicker Test
    - Screen I: Operating Limits, Protection Adequacy, and Coordination Evaluation
- Date Initial Construction Funding Received/Contract Sent.
- Date Full Construction Funding Received.
- Comments on Project Status.

- Metering (Net Meter, Community Distributed Generation, Remote Net Meter, Remote Credit, State Solar for All & Renewable Energy Access, and Community Help).

3. Describe the utility's means and methods for tracking and managing its DER interconnection application process and explain how those means and methods ensure achievement of the performance timelines established in New York State's Standardized Interconnection Requirements.

The Companies prepare a daily "green/yellow/red" report that is circulated to all internal functions that serve a role in the interconnection process. The report provides a summary section that shows each Interconnection report and each department that needs to complete a effort. The report uses green/yellow/red coloring to give a visual aid as to the status of the effort. Green indicates no project is in jepordy of missing a due date, Yellow indicates a project(s) is appoarching due date and Red indicates a project(s) is at due date or has missed duedate. Also within this email transmittal are detials of every yellow and red indaction within the summary section. Sending out this daily report every day ensure applications are tracked and managed in a timely manner as required by the NYSSIR. Data for the report is gathered in an efficient manner through scripted database queries. As the NYSSIR is updated based on ITWG/IPWG collaborations, these revisions are reviewed thoroughly and updated accordingly.

4. Describe where, how, and when the utility will provide a resource to applicants and other appropriate stakeholders for accessing up-to-date information concerning application status and process workflows.

DER developers have access to this information for their own projects using the NYSEG (here) and RG&E (here) websites where reports like the NYSIR Inventory report and Interconnection Project Queue report can be found. It is likely that developers consider this information to be commercially sensitive. If they are willing to authorize us to release it, we will want to evaluate the value of this information to other stakeholders as compared to the expense of providing it. Also maintains a centralized e-mail "distributedgenerationadmin@avangrid.com" for applicants or DER developers to contact with questions or concerns.

The Companies continue to collaborate with the IEDR Program Team and the other JU to provide the status of queued DER projects to stakeholders within the IEDR platform.

5. Describe the utility's processes, resources, and standards for constructing *approved DER interconnections.*

After a project is received from the Interconnections Group, our Integrated Field Construction Design Group will design the recommended upgrades from Distribution Planning and any other line upgrades needed using Company-approved construction standards. The workflow follows defined processes for design and construction. Once the design is complete, it is handed off to line department to construct in the field. This process includes automated notifications to track and monitor progress.

The Companies' standards for the interconnection of distributed generation are contained in Bulletin 86-01, Requirements for the Interconnection of Generation, Transmission and End-User Facilities. Our specifications and requirements are supplemented by the following documents:

NYSEG's Specifications for Customer Electric Service 2.4 kV to 34.5 kV (SP-1099).

NYSEG's Requirements for the Installation of Electric Services & Metering; and

RG&E's Requirements for Installation of Electric Services & Meters.

6. *Describe the utility's means and methods for tracking and managing construction of approved DER interconnections to ensure achievement of required performance levels.*

Our process for tracking and managing construction to interconnect-approved DER begins when the developer has provided 100 percent of the estimated system upgrade costs. There are several steps to the process:

The assigned Manager Programs/Projects sends an email to the appropriate division and corporate personnel which contains details of the project including completed studies, scope and estimate of cost of required system upgrades that have been prefunded by the developer, and applicable project drawings.

The project email is followed up with a kick-off meeting (teleconference) among those included in the project email. Project details and targeted in-service dates are discussed.

The assigned field planner arranges a site visit with the developer and then completes detailed engineering for the interconnection of the generation including creation of work orders for materials, project drawings, etc. and forwards to our Real Estate team.

After all real estate issues are resolved the project work orders are released and requirements sent material procurement.

After materials are received, the job is forwarded to the construction scheduler for scheduling of construction leading to construction until energization is achieved.

For substation scope of work, the assigned Manager Programs/Projects engages the Companies' Customer Funded Project team for substation upgrades. This team manages any needed substation upgrades through engineering to construction.

Final steps include field checkout, as-built drawing transmittal, and issuance of Final Acceptance Letter.

Once a developer makes a payment on a project it is placed in a spreadsheet that interconnections project managers and managers use to track internal and external status of prjoect as well as pertinent information obtain via emails/conferences calls and internal status meetings held.

Throughout this process the Manager Programs/Projects remains in communication with the developer and division personnel.

Headcount:

1 Employee – Review applications for completeness, including application questions and completes Tech Reviews 25 - 50kW

2 Employees – Manages the shared mailbox and coordinates and/or shepherd the reporting efforts between multiples departments to complete reporting

1 Employees / 1 Contractor - Create Work Orders and Purchase Order Creation & Maintenance

3 Employees / 1 Contractor – Manages through study and construction phase; answers interconnection questions and completes reporting for projects 50 - 5000kW

7. *Describe how and when the utility will deliver and maintain its DER interconnection information to the IEDR.*

The Companies' internal IEDR team has developed a pipeline to automatically access the Interconnection DER Database, extract the data fields required by NYSERDA and create two files that are submitted to NYSERDA via SFTP (Secure File Transfer Protocol). The pipeline runs on the first day of each month. Following this process, NYSEG and RG&E share information related to Installed and Queued DERs (such as project ID, Town, Zip Code, Porject Type and Total Construction Charges). Types of DER assets reported include Solar PV Systems, Energy Storage Systems, Wind, Farm Waste, Fuel Cells, Combined Heat and Power Systems, Gas Turbines, Hydro Systems and other Hybrid Combinations.

The internal IEDR team has also developed data quality control mechanisms to automatically ensure the process is completed without errors and to generate a report if anything fails, allowing the IEDR team to identify the root of the problem and address it.

2.12 Advanced Metering Infrastructure

Context/Background: Describe how policies, processes, resources, standards, and capabilities have evolved since the 2023 DSIP Update filing.

AMI field deployment was just beginning when the 2023 DSIP Update filing was published. Since the 2023 DSIP update filing, the Companies have installed over 1.1 million AMI endpoints, comprising 70 percent of all customer endpoints. Consequently, the potential of the AMI system envisioned at the time of the 2023 DSIP update filing is now being realized, with full implementation anticipated to be completed in early 2026.

AMI provides monitoring and visibility at the grid edge. In addition to measuring electricity consumption at 15-minute intervals (5-minute intervals for certain commercial customers), the advanced meters provide operational information including power outages, voltage, and detection of tampering. AMI helps customers manage their energy usage and will support time-varying pricing and innovative rate structures in the 2026 timeframe. The granular data collected by the multitude of advanced meters will help the Companies build dynamic load models and improve forecasts, thereby contributing to more precise distribution planning. Our AMI meters include two-way functionality to support DERs to help meet the State's clean energy goals and allows grid operators to remotely turn meters on and off, eliminating the need for truck rolls.

The Companies' AMI capabilities developed through this initiative include:

1. Customer Data and Billing

   Our AMI deployment includes an upgrade of our billing systems to enable smart meter functionality. Customer information is integrated into customer-facing applications, enabling customers to better manage their electricity and gas usage and energy bills through a web portal, which is on-line and serving customers.

2. Analytics

   Our analytics functions, developed primarily through the IEDR platform and grid edge computing, provide granular energy consumption data and grid performance data to plan and operate the distribution grid more efficiently.

3. Outage Notification

   Real-time outage and power restoration notifications that yield a more reliable and resilient distribution grid. The AMI-OMS integration to be completed by mid-2025 will reduce the average outage duration for certain outages through faster outage identification and quicker determination of the specific location of an open device by analyzing received power-off messages. The +greater visibility at the grid edge will result in more effective outage restoration.

4. Grid Automation

   Operational efficiencies by enabling Grid Automation functions (such as Volt-Amps Reactive ("VAR") Optimization and Fault Location, Isolation, and Service Restoration). By 2028, the Companies will have integrated AMI communications into the grid automation network, contributing to Automated Grid Recovery/Restoration/Fault Location, Isolation, and Service Restoration ("AGR/FLISR") capabilities. AMI data will VVO, which will manage voltage levels to reduce energy losses on the system, and AGR/FLISR will also contribute to faster outage identification and restoration.

Current Progress: Describe the current implementation as of June 1, 2025; describe how the current implementation supports stakeholders' current and future needs.

The Companies, as of June 1, 2025, have deployed approximately 70% of all customer meters, as detailed in Exhibit 2.12:

EXHIBIT 2.12-1: IMPLEMENTATION AS OF JUNE 1,2025

Endpoint Status	Electric	Gas	Grand Total
Legacy Meter	325,869	261,628	587,497
AMI Enabled Meter	1,004,832	352,883	1,357,715
Grand Total	1,330,701	614,511	1,945,212
Legacy Meter	24%	43%	30%
AMI Enabled Meter	76%	57%	70%
Grand Total	100%	100%	100%

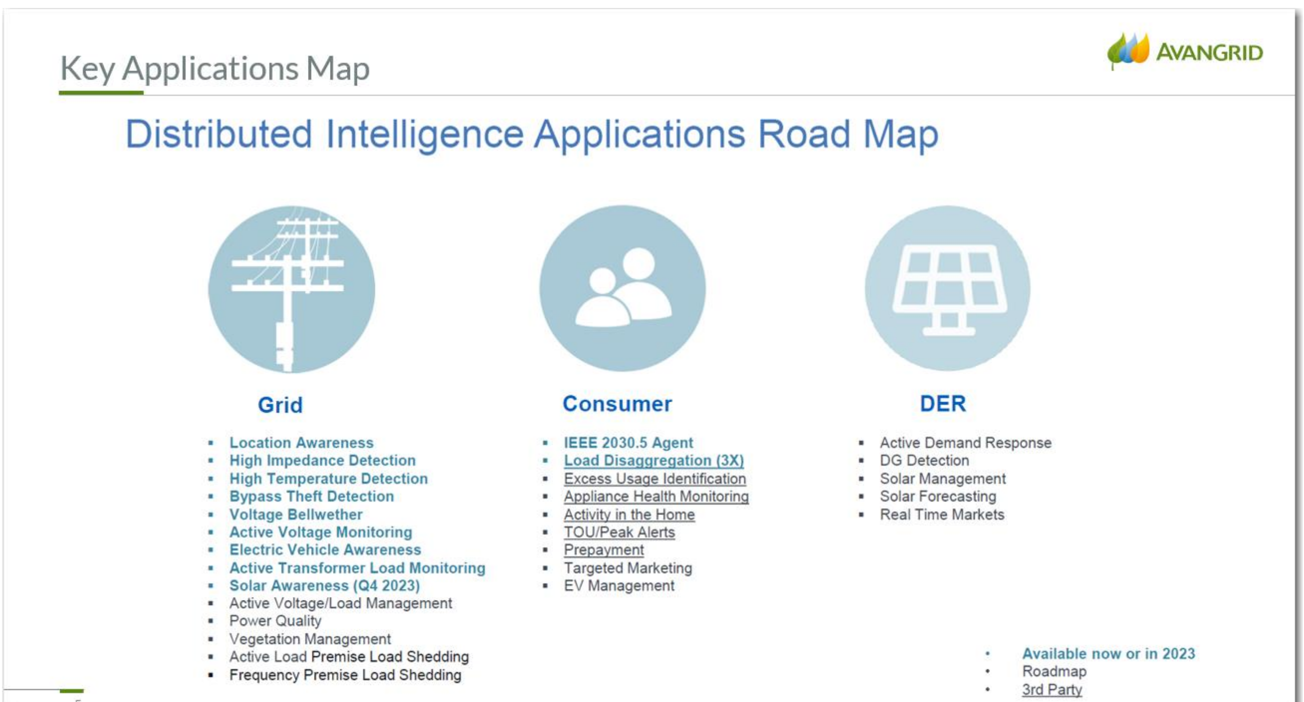
Most of the remaining customer legacy meters will be converted to AMI meters during 2025 with the project scheduled for full completion in the early 2026.

The AMI meters support current and future stakeholder needs in a number of ways.

Customer Data and Billing: The Companies' onsite internal Meter Data Management System ("MDMS") is in production. The MDMS allows the Companies to access meter data in real time to perform various functions, including analytics, and provides the data needed to develop customer load shapes for advanced forecasting and planning. The Companies completed a Customer Relationship Management and Billing ("CRM&B") system refresh, which went live in 2022, and integrated the billing system with IT services to more effectively support AMI integration. Over the near term, the Companies will develop additional energy usage control options and customer segmentation programs for rate design. The Companies are also testing EV charging pilot billing programs. AMI granular data will be able to be used to support time-variable rates in 2026, and AMI distributed intelligence applications are available to identify specific locations of EV's charging along the distribution circuits.

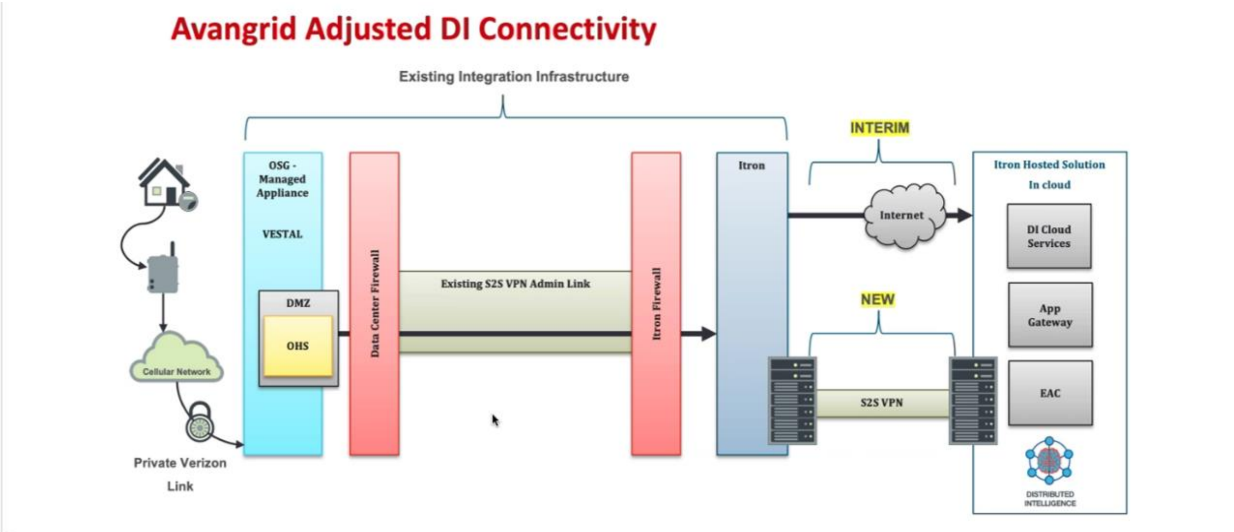
Analytics: The AMI data is being combined with other business systems (billing systems, GIS, SCADA, etc.) data to support DSO. The Companies have completed the hardware deployment for grid edge computing application support. The grid edge computing is being used currently for reporting meter voltage and meter-transformer associations to grid operators. The application is performing in a pilot area today and will be extended to all electric meters during 2025. Additional apps will require a business case to justify implementation. The Exhibit below shows the key grid edge applications that are or will be available.

EXHIBIT 2.12-2: DISTRIBUTED INTELLIGENCE APPLICATIONS ROADMAP



The Exhibit below highlights the Distributed Intelligence architecture and connectivity with other systems.

EXHIBIT 2.12-3: DISTRIBUTED INTELLIGENCE ARCHITECTURE



<u>Outage Notification</u>: Full AMI deployment and integration with the Companies' OMS will be completed by the end of Q3 2025. The integration will result in reduced outage duration and customer outage costs over the entire service territory. The integration of AMI with OMS will reduce the average outage duration for a subset of outage types due to the ability to detect outages more quickly and through more effective management of outage restoration due to greater visibility into outage locations. Shorter average outage duration will reduce customer outage costs.

<u>Grid Automation</u>: Over the long term (2028+), AMI communications will be integrated into the grid automation network and contribute to VVO and FLISR capabilities. AMI data will support ADMS capabilities, such FLISR to reduce outage times.

<u>Future Implementation and Planning</u>: Describe the future implementation that is planned to be deployed by June 30, 2030, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2030 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation; Described where and how plans for topic-related work and investments affect the CGPP; Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

AMI is foundational to fulfilling the Companies' commitments to carbon reduction, clean energy, energy efficiency, and technology innovation. The Companies will implement AMI throughout its service territories upon receiving approval, with full deployment planned to be completed in 2026, which will enable a range of advanced capabilities. AMI meters will support a number of cost-reduction process changes inside the company through automating processes and data collection, outage notifications, and enabling more remote visibility and control. These changes will result in higher customer benefits, such as reduced outage time, lower cost of collecting customer billing information, lower cost of service connections and disconnections, and lower customer service costs in the call center and billing departments.

Coordinated Grid Planning Process: The CGPP is a planning process developed by the Joint Utilities of New York to identify system deficiencies and potential infrastructure that may be needed to reach the State's CLCPA Goals (70% renewable generation by 2030; 100% emission free by 2040). The goal and ultimate outcome of this planning process is to propose infrastructure upgrades that will reduce congestion and help unlock emission free resources across New York. One of the critical inputs in this study is the electrification of heating and decarbonization of the New York economy. Systemwide deployment of AMI will affect the CGPP by giving us better insight into the load profiles and net metering of the system. This will potentially give us more accuracy in future load and DER forecasting as we get closer to 2040, allowing us to be more precise with proposed infrastructure upgrades, specifically on the sub-transmission and within distribution substations (e.g. substation transformer upgrades).

Customer Data and Billing: The AMI deployment is expected to complete by early 2026. Over the near term, the Companies will develop additional energy usage control options and customer segmentation programs for rate design. Longer-term, the Companies will deploy time-varying rates, including for EV charging programs.

Analytics: The Companies have installed AMI software to integrate with the Companies' analytics and deploy edge computing to all AMI devices. Over the long term, the AMI data will be combined with other business systems (billing systems, GIS, SCADA, etc.) data to support the DSO. Interval data is currently being provided in production AMI application.

Outage Notification: Full OMS capabilities will be available on all customer meters by mid-2025.

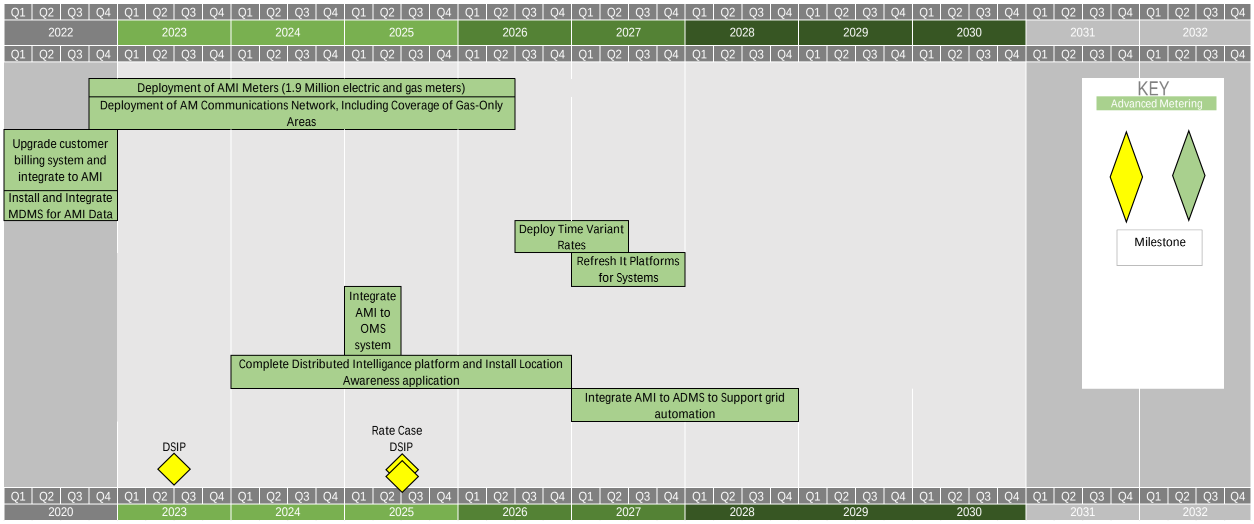
Grid Automation: Over the long term (2028+), AMI communications will be integrated into the grid automation network and contribute to VVO and FLISR capabilities. AMI data will support advanced ADMS capabilities, such FLISR to reduce outage times.

The exhibit below shows our AMI roadmap through 2028, in two different formats.

EXHIBIT 2.12-4: AMI ROADMAP

Capability	Achievements (2023-2025)	Short-Term Initiatives (2026-2027)	Long-Term Initiatives (2028-2030)
Customer Data and Billing	• Installation of over 1,160,000 meters by 3/8/25 (~60% of total) • Installation of 95% of AMI communications network • CRMB refresh and integrate IT software for billing systems • Deployed internal MDMS	• Finish installation of all meters • Finish AMI network • Complete hardware refresh • Deploy time-varying rates, including EVs	
Analytics	• Completed grid edge computing hardware installation • Integrated IT software		
Outage Notification	Complete AMI-OMS integration by end of Q3 2025		
Grid Automation		• Begin to integrate AMI and communications networks with grid automation	• Advanced ADMS capabilities

EXHIBIT 2.12-5: AMI IMPLEMENTATION TIMELINE



Integrated Implementation Timeline: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2030. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

Exhibit 2.12-4 above highlights the Companies' AMI roadmap.

Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E have identified three key risks that relate to the deployment of AMI, and have taken measures to mitigate each risk, as shown in the exhibit below.

EXHIBIT 2.12-6: AMI RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Deployment and Performance:** Deployment risk related to schedule and cost overruns; performance risk related to technology performing per expectations	• With deployment of customer endpoints 60% complete, this risk has diminished over time.
2. **Customer Acceptance:** Uncertainty regarding AMI benefits and concerns about health, safety, privacy, and other perceived threats	• We developed a comprehensive customer engagement plan to communicate the benefits of AMI and a realistic, informed assessment of perceived threats
3. **Security Risk:** Key operating systems are subject to security risks during deployment since third-party vendors are supporting AMI implementation. Customer information is subject to security risks once AMI is deployed.	• The Companies developed a detailed and comprehensive security plan for protecting key systems and customer information.

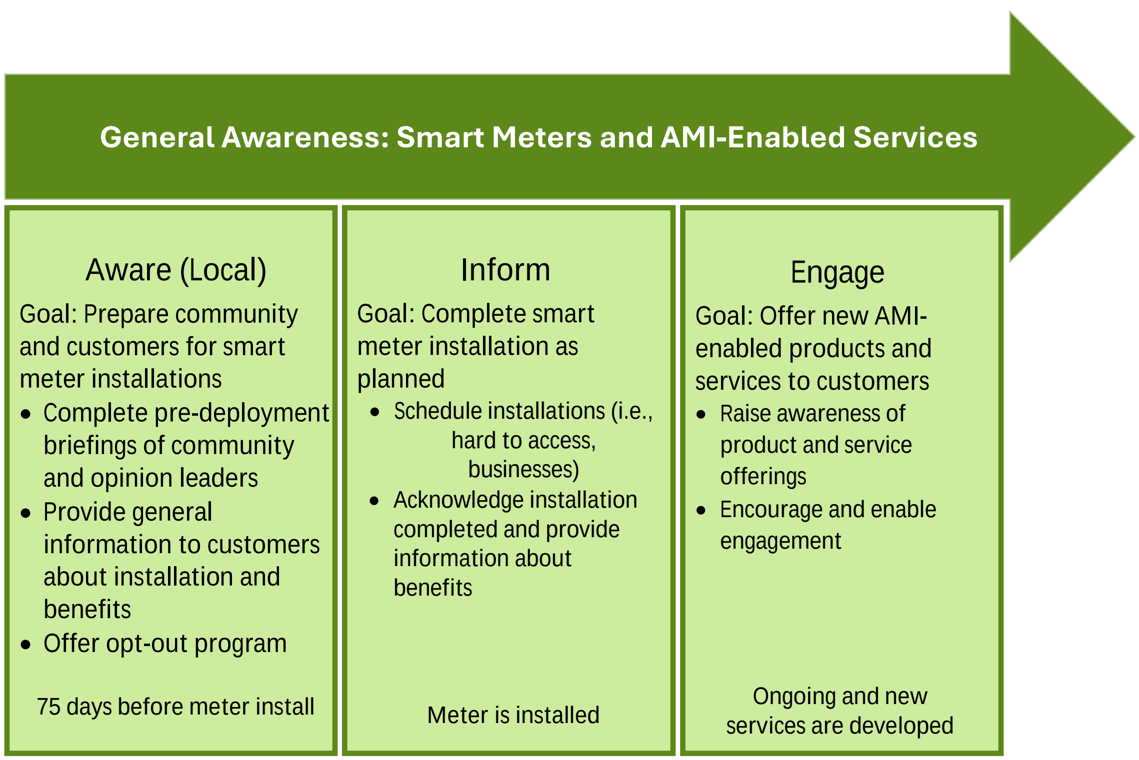
Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category's needs will be met over time; Describe and explain the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

We have developed a detailed outreach and engagement plan to ensure that the DER developers and other stakeholders and customers understand how to take advantage of the new AMI-provided capabilities. This plan provides a roadmap to build and operate a customer communications program and identifies metrics that enable the plan to be continuously improved over time. The plan is central to the overall deployment of AMI, which is not only a physical meter replacement program but also a communications program to ensure our AMI asset is effectively utilized. This plan focuses on customer benefits, as well as leveraging research and best practices.

Our customer engagement plan consists of three phases designed to help customers become: We continue to follow these guidelines effectively.

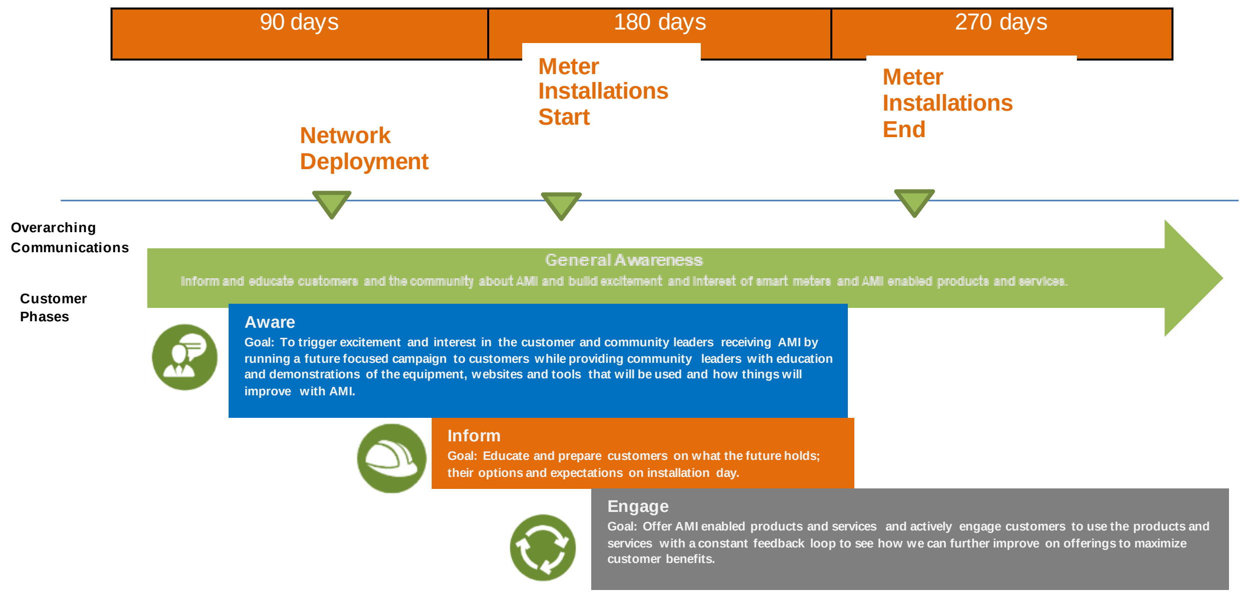
1. **Aware**: A series of communication campaigns designed to create excitement and interest, while educating customers about smart meter benefits and the general scope and timing of the deployment.
2. **Informed**: A series of communication campaigns designed to prepare customers for deployment, reiterate meter benefits, and provide information on available program opportunities for each customer; and
3. **Engaged**: Ongoing communications, starting from the day of meter installation, to provide individual customers with the knowledge and insights to participate in smart meter opportunities.

EXHIBIT 2.12-7: CUSTOMER ENGAGEMENT PLAN



Each phase includes campaigns with defined targets, messages, audiences, and communication channels. Metrics are being developed to track participation and behavioral changes. We will develop and adjust communication messages as necessary and select appropriate communication channels for each message. The exhibit below shows the approximate timeline for each phase.

EXHIBIT 2.12-8: APPROXIMATE CUSTOMER OUTREACH AND EDUCATION TIMELINE



Approximate Customer Outreach and Education Timeline

Through the end of 2024, the Companies hosted 38 open houses to address customer concerns directly and in-person. In addition, 75 events to increase awareness of the AMI technologies have taken place. Exhibit 2.12-9 provides measures of customer awareness of AMI in service areas before and after major installation efforts were completed. The Exhibit shows widespread awareness of AMI after the installation efforts, indicating the open houses and other events to introduce AMI to the service areas have been effective.

EXHIBIT 2.12-9: CUSTOMER AWARENESS OF AMI BEFORE AND AFTER OUTREACH AND INSTALLATION EFFORTS

Opco	Division	Baseline Awareness	Post-Install Awareness
NYSEG	Ithaca	61%	**94%**
RG&E	Rochester Central (1 of 3)	59%	**94%***
RG&E	Sodus	50%	**94%**
NYSEG	Binghamton	57%	**93%**
NYSEG	Brewster	58%	**90%**
NYSEG	Lancaster	37%	**90%**
RG&E	Canandaigua	51%	**93%**
RG&E	Rochester Central (2 of 3)	59%	**97%***

The AMI interval data will be available as meters are deployed; however, the dependency will be when the DER application third-party access is ready for use. AMI technology will also support DERs developer needs through the measurement of both hourly (or more frequent) power delivered to the customer and power delivered to the grid. This data is essential to DER developers' accurate planning, implementation, and visibility of the distribution system. AMI will provide detailed information on distribution circuit load, voltage, and hosting capacity needed to identify and plan optimal locations for DERs siting decisions. More granular AMI data will improve estimates of hosting capacity, which is a data-driven exercise and depends critically on the availability and quality of granular data. This is discussed further in 2.9 (Hosting Capacity). As discussed in 2.2 (Advanced Forecasting), detailed data will support accurate forecasts of load by location (substation and circuit) and time of day.

Additional Detail

Advanced Metering Infrastructure (AMI) provides grid-edge measurement, data acquisition, and control capabilities which are either essential or beneficial to a number of important functions in modern distribution system. Granular time-series data from smart meters and other intelligent devices at customers' premises enable advanced analyses, innovative rate designs, and customer engagement strategies which benefit both the customers and the grid. Voltage sensing and measurement functions support increased system efficiency and enable improved outage detection and restoration processes. Capabilities supporting DER measurement, monitoring, and control are essential for DER integration.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to AMI:

1) *Provide a summary of the most up-to-date AMI implementation plans, including where AMI has been deployed to date*

Exhibit 2.12-10 provides the current AMI metering deployment plan for both NYSEG and for RG&E, including detail for electric meters installed and also gas meter communication devices (ERT's) installed. As indicated above, the Companies as of June 1, 2025, have deployed approximately 70% of all customer meters. All AMI back office integration with key systems and also the AMI communications network to the back office will be completed by the end of 2025.

EXHIBIT A.12-10: NYSEG AND RG&E ADVANCED METERING DEPLOYMENT PLANS

Year	NYSEG E	NYSEG G	RG&E E	RG&E G	NYSEG	RGE	Total
2022	3,850	68	-	50	3,918	50	3,968
2023	106,286	26,998	105,290	42,028	133,284	147,318	280,602
2024	389,618	89,406	145,245	125,731	479,024	270,976	750,000
2025	370,035	129,965	118,744	131,257	500,000	250,000	750,000
2026	62,161	35,556	25,827	32,440	97,717	58,268	155,985
All	931,950	281,993	395,106	331,506	1,213,943	726,612	1,940,555

Note: 2026 installations will be "clean-up" installations to address customers that were not converted to AMI during the scheduled deployment period from 2022 to 2025, including growth in the service territory.

2) *Provide a summary of all new capabilities that AMI has enabled to date, and how these capabilities benefit customers, including, as applicable, customer engagement, energy efficiency, and innovative rates.*

AMI meters provide two measurement channels that record power inflows and power outflows at each DER site. In addition, AMI meters provide voltage measurements at each DER site. These AMI meter capabilities will help with load planning, distribution circuit management, hosting capacity, and locational value assignment. AMI data will help validate our current 8760 forecasts to measure accuracy and provide insights into changes in customer behavior (e.g., load shapes changes) in response to programs and initiatives, such as EV home charging impact on circuit loads.

NYSEG and RG&E distribution planners will be able to review distribution circuit loads and provide more accurate estimates of the hosting capacity of each circuit that reflect interval consumption data and frequent measurements of voltage.

AMI meters help with the following:

- AMI will allow us to develop accurate and detailed load curves for each circuit segment.
- Granular consumption data from AMI meters will support the development of time-varying rates.
- AMI data will help the DER operators understand the value of kilowatt-hours produced at a particular time and inject power back into the grid when it has the most value.
- AMI data will provide verification of DER performance and support transactional markets.

AMI meters provide more sophisticated voltage monitoring for all customers, which can eventually enable VVO functions to make voltage adjustments without risk of compromising service to any individual customer. Separate voltage sensors at key points along the circuit provide data to support VVO operations, but the more detailed AMI voltage data will support the fine tuning of the operation plan to optimize savings. AMI technology software and firmware is designed to integrate with VVO systems to optimize the transfer of information between the smart meters and the VVO controller. This integration should increase the incremental improvement of VVO generated by use of smart meter data.

AMI meters issue power-off and power-on messages in real time. These messages support more timely outage identification, more accurate outage scoping, and faster, more efficient service restoration after faults are resolved. All but the largest AMI meters (approximately 95%) will have remote shutoff capabilities. In addition, AMI meters can be "pinged" when individual customers report outages, so that situations where the power outage problem is on the customer's side of the meter can be readily identified and "false alarm" truck rolls can be avoided.

AMI meters supply granular interval consumption data that supports the creation of time-varying rates. Rates can be set higher for times when power is more expensive to supply and lower for times when power is less expensive to supply. These price signals can help customers find the most efficient times to use power and the most profitable times to return power to the grid. Consequently, customers can take an active role in managing their power production and consumption, and overall costs of using power consequently decline. Our AMI web portal that communicates usage patterns helps customers understand the opportunities available or with managing their bills.

The OptimizEV pilot incentivizes residential EV charging load shifting for AMI customers. The program was made possible by implementing the AMI rollout through ESC and expanded to the Companies' service territories. Additional customer segmentation programs and time-varying rates will result from the AMI deployment in the future.

3) *Describe the AMI-acquired data and information that is planned to be available through the IEDR.*

AMI interval consumption data (15 minute intervals for residential customers and 5 minute intervals for some commercial customers) is being provided to the IEDR.

4) *Describe where and how DER developers, customers, and other stakeholders can access up-to-date information about the locations and capabilities of existing and planned smart meters.*

The NYSEG and RG&E website home pages that include maps of the deployment activity, answers to frequently-asked questions, and how to exploit the benefits enabled by smart meters.

5) *Provide a summary of plans and timelines for future expansion and/or enhancement of AMI functions.*

The Companies intend to complete the meter deployment by early 2026. Please see Future Implementation and Planning section above for more details on additional enhancements.

6) *Describe where and how each type of AMI-acquired data is stored, managed, and shared with, and used by other utility information systems such as those used for billing/compensation, customer service, work management, asset management, grid planning, and grid operations.*

Currently, New York AMI data is stored in the MDMS, and the project team is working with respective stakeholders to determine requirements for various initiatives.

2.13 Beneficial Locations for DERs and NWAs

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2023 DSIP Update filing.

NWA and beneficial locations refer to the process of identifying locations with potential for localized DERs deployment to address projected system growth or capacity needs, and procuring NWAs intended to make lower-cost investments in grid infrastructure by deferring or avoiding traditional infrastructure investments in "wires" solutions. NWAs benefit NYSEG and RG&E and customers, as NWAs replace or defer traditional "wires" projects with DERs and other market-based solutions, potentially providing cost savings, and delivering environmental benefits, while maintaining system reliability and resiliency.

Since 2023, the Companies have continued to make progress improving their contracting process, project identification process, as well as their measurement and verification process for projects that are implemented. Once a project opportunity is identified, the Companies' NWA team will develop a RFP to send out to the market for a technology agnostic solution. Upon receiving bids back from third party developers, the Companies perform a Benefit Cost Analysis utilizing the Companies' BCA Handbook. Following the BCA analysis and solution selection, the contracting process begins, and the project enters the construction/implementation phase. Upon completion of this, the measurement and verification period will begin to monitor the success of the selected third-party solution(s). The procurement of NWA solutions is discussed in more detail in the following sections of the DSIP filing.

Current Progress: Describe the current implementation as of June 30, 2025; describe how the current implementation supports stakeholders' current and future needs.

The Companies procure NWAs through a competitive solicitation process and identify locations on the grid where DERs could help address constraints, voltage issues and potentially defer grid investments or where other electrification load can be accommodated. After applying lessons learned from earlier NWA development and contract negotiations, the Companies developed a standard NWA contract to streamline the advancement of future NWA opportunities. The Companies have also implemented monitoring and verification processes and continue to apply MCOS and VDER methodologies. In 2023, NYSEG commissioned its first NWA project in the Village of Stillwater.

In 2025, the Companies plan to release two RFPs to solicit NWA solutions for the Ferndale Substation in the Liberty division and Holland Substation in the Lancaster division. The Companies will look for third party developers to provide a solution to help reduce the peak load in these areas and reduce the chance of potential overloads on the system.

In 2027, the Companies plan to revisit the Java microgrid backup supply power project, which was placed on hold, with a goal of releasing an RFP in 2027. The Java peak shaving project was put on hold due to lower observed loading levels resulting from circuit conversions/transfers to neighboring circuits.

Our recently identified projects help to address all stakeholders' needs. Implementing NWA's helps to achieve stakeholder needs by helping to integrate non-carbon emitting resources, provides rate payers cost savings through deferred capital projects, helps to address reliability concerns by providing a back-up source of energy, and helps provide flexibility to the planning process by providing additional solutions to implement.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2030, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2030 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation; Described where and how plans for topic-related work and investments affect the CGPP; Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

To further scale NWA solicitations and project implementation, the Companies have taken steps to align internal processes (e.g., ISP processes) to identify NWA opportunities earlier on in planning process, with a focus on projects that fulfill CLCPA targets including providing consideration to DAC.

Over the near term, the Companies will continue to refine monitoring and verification protocols and make iterative improvements to the NWA contract administration. Over the long term, with the GMEP and other technologies in place to perform more frequent system studies, the Companies will develop planning processes to identify beneficial locations and VDER stack planning processes

NWAs help provide learning opportunities for the CCGP by providing the Companies with an opportunity to learn/capture best practices through the integration of DERs. The CCGP process helps inform NWAs as of the likelihood where DERs would have the most impact based on location. To date, the Companies have not used the CCGP to inform NWA project locations. The exhibit below shows the status of the Companies' existing and potential future NWA projects.

EXHIBIT 2.13-1: NYSEG AND RG&E'S NWA PROJECTS

Company	Project	Proposed In Service Date	Need	Status
NYSEG	Java Peak Shaving	2030	<1 MW peak shaving	Project is currently on hold until 2027
NYSEG	Java Microgrid	2030	4 MW redundancy (failure of existing transformer)	Microgrid will be NYSEG-owned and operated; Project currently on hold until 2027
NYSEG	Stillwater	In Service	<1 MW peak shaving power quality	In-service, Measurement and Verification and contract management until 2032
NYSEG	Ferndale Substation	2028	Sizing still in progress	Project to go to RFP for a 3rd party developer solution in 2025.
NYSEG	Holland Substation	2028	Sizing still in progress	Project to go to RFP for a 3rd party developer solution in 2025.

The Exhibit, below, shows the Companies' beneficial locations and NWAs roadmap over the DSIP period through 2030.

EXHIBIT 2.13-2: BENEFICIAL LOCATIONS AND NWAS ROADMAP

Capability	Achievements (2023-2025)	Short-Term Initiatives (2026-2027)	Long-Term Initiatives (2028-2030)
Execute Competitive RFP & Contracts	• Improved quality and availability of information to inform and de-risk RFP responses (e.g., load data at circuit and substation level, customer data) • Reflected contracting lessons learned • Commissioned Stillwater NWA	• Continue to improve quality and availability of information to inform and de-risk RFP responses (load data at circuit and substation level, customer data) • Continue to improve standard terms and conditions agreement • Complete procurement process to advance Java microgrid • Complete procurement process to advance Ferndale Substation NWA • Complete procurement process to advance Holland Substation NWA	
Administer NWA Contracts	• Improved quality of information for Measurement and verification • Fully commissioned Stillwater NWA in November 2023 • Installation of communications system for measurement and verification at Stillwater NWA site. •	• Continue to refine M&V and monitoring and control "back-end" processes • Continue to administer Stillwater contract and leverage lessons learned to inform future NWA projects • Establish requirements for company-ownership and operation of DERs assets • Administer all new NWA contracts	
Scale NWA Function	• Developed screening methodology to identify NWA projects earlier in the investment planning process leading to a new NWA opportunity • Comprehensive Area Studies Completed which will inform new NWAs	• Continue to build portfolio of NWA projects and deploy projects • Implement new NWA projects that have been identified proactively or through Comprehensive Area Studies	
Estimate the Locational Value of DERs to the Grid	• Applied approved MCOS/VDER methodologies	• Continue to Incorporate granular AMI and system data into NWA analyses • Continue to develop and build upon VDER stack planning process	

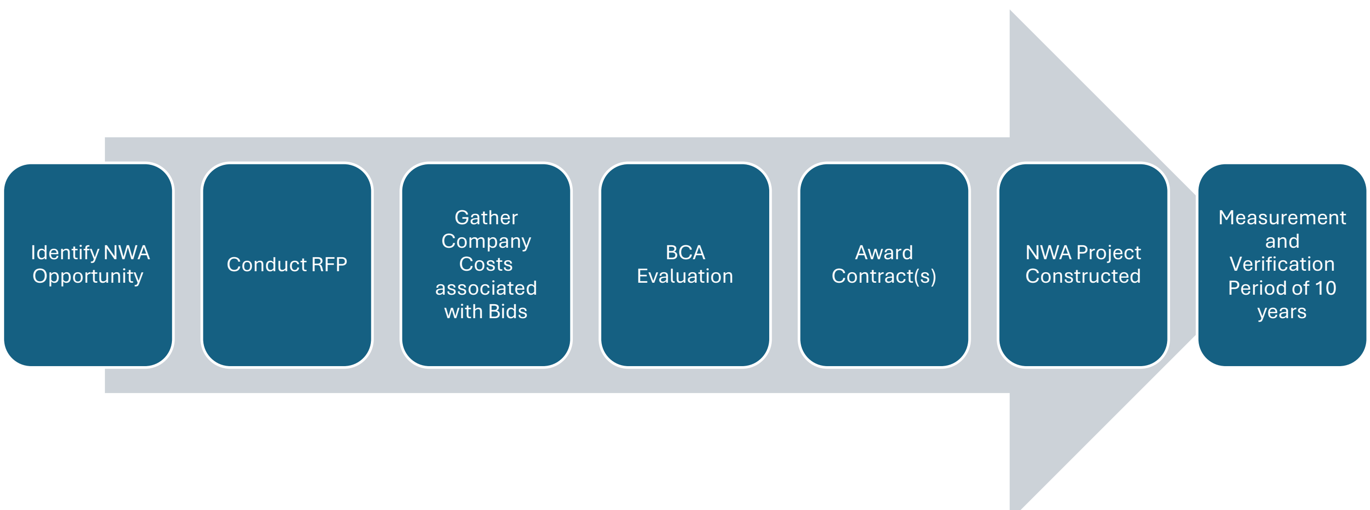
<u>Integrated Implementation Timeline</u>: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2030. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

The Joint Utilities have considered common beneficial locations identification and NWA procurement approaches at the distribution level where possible. The goal of this was to reduce negotiations and help expedite projects. Liquidated damages/settlements processes could also be a commonality for dispatch response to expedite projects.

The Joint Utilities working group is currently on hold, though the utilities developed streamlined approaches to improve the NWA process through lessons learned at each project phase (*e.g.*, project identification phase, contracting phase, procurement, construction, and implementation phases). The Joint Utilities are aligned with their methodologies for NWA projects. Please see the exhibit 2.13-2, above, for the Companies' roadmap and the identified projects that the Companies have in development at this time.

An NWA project takes 36 months from the time they are identified until the time they are fully installed. The key milestones for NWA projects are identified below:

EXHIBIT 2.13-3: KEY MILESTONES FOR NWA PROJECTS



Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s).

NYSEG and RG&E have identified several risks that relate to the identification of beneficial locations and NWAs, and have taken measures to mitigate each risk, as shown in Exhibit 2.13-4.

EXHIBIT 2.13-4: BENEFICIAL LOCATIONS AND NWAS RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Data:** DSO performance will depend on the quality data that is relied upon by the DSO to validate the performance of NWAs and identify potential NWAs	• NYSEG and RG&E are designing the GMEP to develop an accurate up-to-date specification of the network including connected DERs and incorporate governance and data processes and flows
2. **Customer Value:** DSO must be efficient and enable reliable, resilient, safe distribution service	• NYSEG and RG&E advocate for policies (e.g., CLCPA, REV, etc.) that align with customer value • Beneficial locations are an important means of compensating DERs for the value they provide to the grid
3. **Cost Recovery:** Timely cost recovery is necessary to maintain financial health	• Maintain existing NYSEG and RG&E financial controls and regulatory accounting to ensure appropriate cost recovery
4. **Siting and Approvals:** Garnering siting and municipal approvals can be challenging	• A focus on DAC and environmental equity in siting NWAs to address a lack of NWA opportunities • Early discussions with stakeholders such as authority having jurisdiction ("AHJ"), emergency response teams, municipalities, and communities • Engage in outreach to communities and other stakeholders to communicate on projects
5. **Supply Chain Delays:** Supply chain delays and equipment lead times can result in project scheduling delays	• Project prioritization based on timing and magnitude of project need(s) and benefit(s) • Reallocation of existing equipment stock if possible
6. **Aging Infrastructure and Capital Funding Constraints:** Lack of NWA opportunities due to aging infrastructure and capital funding constraints	• Explore expanding BCA framework to include additional benefits (*e.g.*, CLCPA) • Leverage outside funding opportunities when applicable or if available
7. **Limitations on Aligning Internal Processes:** Limitation on aligning internal processes to better enable NWA opportunity identification earlier on in planning process	• Give consideration to NWA solutions earlier in the review process to speed up implementation • Improve internal process updates, including developing an NWA suitability screening form to streamline internal NWA reviews and an internal NWA process training to expand awareness within the Companies
8. **Developer Risks:** Lengthy and complex contract negotiations between utility and developer due to developer's risk aversion	• Adoption of ownership-agnostic language in RFPs to address developer risk aversion • Provide consideration to a payment structure that offers additional incentives to developers that streamline contract negotiations and hit milestones in the contract negotiation phase in a timely manner

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category's needs will be met over time; Describe and explain the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

The Joint Utilities established a DERs Sourcing and NWA Suitability Criteria Working Group to engage stakeholders on issues pertaining to beneficial locations and NWAs. Workshops and conferences are open to the public via in-person meetings and webinar access.

The team engages with both internal and external stakeholders on assessing NWA needs. Internal stakeholders include the NWA, system planning, project development, interconnection, regulatory, legal, operations, transmission planning, leadership, energy land management, marketing, government, and community outreach, procurement, and environmental teams. External stakeholders include developers, regulators, LMI communities, DAC communities, environmental groups, utility customers, community leaders, government officials, emergency response personnel, and the Department of Public Safety. This communication is done through email, notifications posted online, in person meetings, virtual meetings, and other methods of communication. Attending conferences and other speaking engagements also helps with developing relationships with interested stakeholders.

The Companies aim to deliver safe, reliable, and efficient service to customers, while also promoting environmental equity and conservation. The Companies incorporate the goals and needs of stakeholders through various methods, including the public comment period within the SAPA process, working groups, technical conferences, and stakeholder forums.

The Companies prioritize NWAs located within disadvantaged communities and projects that focus on environmental justice. The Companies also implement the newest and most robust technologies, issuing technology-agnostic solicitations RFPs, and selecting energy efficient and environmentally friendly solutions. The Companies also strive to issue transparent and straightforward RFPs to lower barriers to access, create clarity around the utility's goals in issuing the RFP, and to yield well-tailored responses from a broad group of stakeholders.

Additional Detail

To help promote productive DER development, it is essential that the utility identify, characterize, and publicly present the locations in its service area where DERs and/or energy efficiency might provide significant benefits to the distribution system and/or to the bulk electric system. Based on its criteria for evaluating opportunities for non-wires alternatives (NWA), the utility then selects some of those locations for NWA procurements and/or energy efficiency measures that will benefit the distribution system.

In previous DSIP filings, per the 2018 Guidance, the utilities have separately described their processes for identifying beneficial locations, evaluating NWA suitability, and procuring non-wires solutions. However, as the utilities have evolved their planning processes to perform these functions, they have become part of a continuous process that begins with integrated planning. Therefore, the utility's 2025 DSIP update should reflect this updated process by combining the topics of identification of beneficial locations, NWA suitability assessment, and procurement processes into one cohesive discussion.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to the utility resources and capabilities supporting identification and presentment of beneficial locations for DERs and NWAs:

The Companies are committed to providing system information to DER developers that helps them locate DERs where it provides benefits to our customers and the grid, as well as promising business opportunities for DER developers.

1) *Describe where and how developers and other stakeholders can access resources for:*

    a. *accessing up-to-date information about beneficial locations for DERs and/or energy efficiency measures; and*

    Information related to potential upcoming NWA opportunities that have passed the NWA suitability criteria are posted to the NYSEG and RG&E websites.[149] The locations that have a growth or capital need are identified on the VDER tariff, along with the associated LSRV compensation based on the identified traditional wires solution.

[149] Current NYSEG and RG&E NWA solicitations.

b. *efficiently sorting and filtering locations by the type(s) of capability needed, the timing and amount of each needed capability, the type(s) and value of desired benefit, the serving substation, the circuit, and the geographic area.*

The development and identification of "DERs Beneficial" locations for NYSEG and RG&E will be coordinated with the identification of "high value" distribution areas suitable for LSRV denomination under NYSEG and RG&E's electric MCOS studies. The Companies identify load pockets or constrained areas with capital expansion projects that are valued in the MCOS studies. As noted above, there are methodological issues that need to be resolved.

Once a wire solution has been defined, the Companies will identify all circuits that are connected to the identified investment and identify them as beneficial locations. Interconnection of DERs that reduce peak loading on those circuits can potentially defer investment at the substation or upstream feeder. The approach to select DERs Beneficial locations will be independent of hosting capacity limits; hosting capacity limits will be separately established for the specific circuit/feeder to reflect whether the feeder or transformer can reliably accommodate the DERs without material system upgrades. Analysis of hosting capacity considers, among other things, voltage/power quality constraints, thermal constraints, protection limits, safety, and reliability. The goal is to signal these high value (DERs Beneficial) locations to the DER Developers to meet incremental demand on those circuits (or equivalently, the avoided costs of reducing demand by interconnecting DERs.) The Companies will provide public information regarding LRSV for all locations to encourage optimal DERs deployment via access to the web-based portal. The utilities will provide a web-based application that will identify the high value areas. The VDER tariff will be the mechanism to communicate beneficial locations for DERs and NWAs.

The specific high value areas will be updated every three years, or more frequently if the utility MCOS are updated more frequently. Whenever a high value area experiences a cumulative DERs addition in sufficient capacity so that the established DERs cap for the area is achieved, the LSRV value in that area will be re-set to zero and the area will not be considered a high value area until the next investment cycle is due.

2) *Describe the means and methods for identifying and evaluating locations in the*

distribution system where:

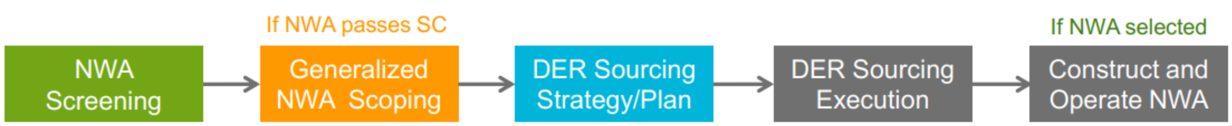
a. *an NWA comprising one or more DERs and/or energy efficiency measures could timely reduce, delay, or eliminate the need for upgrading distribution infrastructure and/or materially benefit distribution system reliability, efficiency, and/or operations; and/or*

Our strategy for NWAs is to (1) build a portfolio of cost-effective NWA DER projects that provide reliable alternatives to traditional wires solutions; (2) comply with regulatory directives; and (3) learn from and work cooperatively with the Joint Utilities and other stakeholders. The Companies are actively involved with the Joint Utilities' DERs Sourcing Working Group to address NWA solicitation and contracting issues.

The Companies look for energy efficiency opportunities that in areas have been identified as NWA candidates. It is important to develop and target energy efficiency options to areas of the system that have been identified to require investments to meet capacity needs as these will result in the greatest cost savings.

NWAs have become an integral part of the Companies' planning process. The exhibit below shows the process flow diagram for the life of an NWA project, which consists of five steps:

EXHIBIT 2.13-5: BENEFICIAL NYSEG AND RG&E NWA PROCUREMENT PROCESS



Note: SC refers to NWA suitability criteria, which is further defined below.

These steps are:

1. <u>NWA Screening</u>: Identify capital projects proposed to meet a system need and apply the Companies' specific NWA suitability criteria.[150] Projects are candidates for an NWA if they meet the suitability criteria, including (1) a minimum of 36 months until time of need, (2) construction costs exceeding $1 million, and (3) the type of project as stated in the suitability criteria. A conceptual T&D solution is developed that addresses the initial system need and any other asset needs.

[150] The suitability criteria matrix was developed with the Joint Utilities in 2017 and is applied to all potential NYSEG and RG&E NWAs. Joint Utilities' Supplemental Information on the Now-Wires Alternatives Identification and Sourcing Process and Notification Practices. Case 16-M-0411 and Case 14-M-0101.

Projects that pass the NWA suitability criteria are evaluated and ordered according to time of need.

2. Generalized NWA Scoping: Identify timeline for NWA need, determine suitable and optimal NWA locations, and determine NWA performance attribute requirements.
3. DERs Sourcing Strategy and Plan: Evaluate DERs technical and program applicability, identify solicitation approach (i.e., single vs. portfolio approach), and develop the NWA RFP.
4. DERs Sourcing Execution: Complete RFP process, evaluate NWA proposals and BCA, make decision to proceed with traditional wires solution or NWA, and initiate negotiations leading to an executed contract.
5. (If NWA Selected) Construct and Operate NWA: Interconnect NWA (if applicable) after completing necessary engineering, procurement, permitting and construction activities, test and commission NWA, and commence administering the NWA contract, including the M&V process. In almost all cases, the Companies' involvement in the last step of the NWA process will include interconnection (if applicable) and administering the NWA contract.

As the Companies gain experience with the NWA process, we are building three capabilities necessary to efficiently execute NWA procurement processes, including:

1. Execute Competitive RFPs and Contracts: The Companies are developing NWA RFP and contracting capabilities. This includes identifying and incorporating lessons learned from each RFP process to help streamline associated processes and assist in the development of a standardized approach to RFPs and contracts.
2. Administer NWA Contracts: The Companies will develop capabilities to administer NWA contracts. This is a future capability the Companies will develop after executing an NWA contract.
3. Scale NWA Function: The Companies are also building capabilities to scale NWA functions, focused on building a portfolio of NWA projects by integrating consideration for NWAs earlier on in the planning process.

b. one or more DERs and/or energy efficiency measures including increased value-based customer incentives could reduce, delay, or eliminate the need for upgrading bulk electric system resources and/or materially benefit bulk *electric system reliability, efficiency, and/or operations.*

NYSEG and RG&E agree that an NWA could be increasing demand response or energy efficiency incentives by bundling NWA incentives with the current programs offered by the Companies. To date, this has not been a solution proposed by a third party developer that has been implemented.

3) *Describe how the NWA procurement process works within utility time constraints while enabling DER developers to properly prepare and propose NWA solutions which can be implemented in time to serve the system need. Details should include:*

After developing the list of potential NWA projects, the NWA RFPs are prioritized by time of need. The Companies then plan a tentative schedule for procuring NWA solutions, focusing first on the near-term, high-priority projects. Although our initial contracting efforts have taken more time than anticipated, we continue to believe that the existing three-year lead time relative to the time of need that is defined in the suitability criteria is sufficient time to execute a project. If a project need is identified within one or two years, it is not reasonable to pursue an NWA solution. Based on our experience to date, the process of identifying a need, issuing an RFP, working through the solicitation, evaluating proposals, negotiating a contract, and executing the project takes at least three years.

a. *how utility and DER developer time and expense are minimized for each procurement transaction;*

The interests of the Companies, customers, and NWA bidders are clearly aligned, and all stakeholders are interested in minimizing the time and expense associated with the NWA procurement process. We debrief and identify lessons learned after each RFP process with internal and external stakeholders to identify potential efficiencies. An NWA is a reliability support agreement and is proving to be a challenging contract to negotiate. The Companies have applied lessons learned from the procurement process, as discussed above (e.g., developing a standardized contract, adopting owner-agnostic RFP language).

b. *how standardized contracts and procurement methods are used across the utilities.*

NYSEG and RG&E have participated in the Joint Utilities' DER Sourcing Working Group. The group worked together to develop a standardized contract and to provide flexibility for planners and developers to facilitate a streamlined process. The group discussed the status of RFPs and shared lessons learned and questions with other Joint Utilities' members, as well as ongoing DER sourcing procedures across the country.

4) *Describe where and how DER developers and other stakeholders can access up-to-date information about current NWA project opportunities.*

NYSEG and RG&E websites provide a resource to DER developers and other stakeholders for accessing up-to-date information about current NWA project opportunities.[151] The websites are periodically reviewed and updated based on the number of RFPs issued and when new opportunities are identified. When NYSEG/RG&E issue an NWA RFP, the RFP is emailed to the Companies' NWA distribution list, posted to the Companies' applicable website, linked to the Joint Utilities and REV Connect websites, and filed with the Commission under Case 14-M-0101. Additionally, as of July 1, 2019, all NWA RFP opportunities posted to the Companies' websites will include a description of any utility-owned suitable, unused, and undedicated land that may be applicable to the NWA solution.

5) *Describe how the utility considers all aspects of operational criteria and public policy goals when deciding what to procure as part of an NWA solution.*

The operating/ NWA performance attributes of proposed technology solutions are evaluated as part of the RFP bid evaluation process, to ensure that the proposed NWA solution meets the identified system needs. In addition, NWA proposals are subject to analysis using the accepted BCA framework that considers societal costs and benefits. The Benefit-Cost Analysis Handbook (BCAH) methodology considers the cost of carbon in conducting the BCAs. In selecting proposals The Companies will consider the impact on society as a whole by conducting the Societal Cost Test which is approved cost test for NWA solutions. The Societal Cost Test is used to support clean energy public policy goals. The Companies also consider the Utility Cost Test and Ratepayer Impact Measurement to ensure that the project benefits all Stakeholders.

Operating criteria is vetted through internal processes and stakeholders to ensure that the solution fits the operational needs. Internal stakeholders include the NWA, system planning, project development, interconnection, regulatory, legal, operations, T&D planning, leadership, energy land management, marketing, government, and community outreach, procurement, and environmental teams.

[151] Current NYSEG and RG&E NWA solicitations.

5) *Describe where, how, and when the utility will provide DER developers and other stakeholders with a resource for accessing up-to-date information about all completed and in-progress NWA projects. The information provided for each project should:*

As described in the "Order Adopting Joint Proposal" under case 22-E-0317 and 22-E-0319, NWA reports upcoming projects and completed projects through quarterly reports. In the quarterly report the Companies show (1) NWA project expenditures and all relevant details with respect to project costs; (2) a description of the NWA project activities; (3) anticipated project in-service dates; (4) NWA cost and incentive recoveries; and (5) identification of operational savings or other benefits. These are filed under case 22-E-0317 and 22-E0317.

In addition to the quarterly reports, each NWA project that is in the implementation phase has an Implementation Plan filed no later than January 31 of the respective year. The plan is filed under the respective operating company case. For NYSEG, it is Case 22-E-0317 and for RG&E it is Case 22-E-0319.

a. *describe the location, type, size, and timing of the system need addressed by the project;*

Exhibit 2.13-6 provides information on current and future NWA projects.

EXHIBIT 2.13-6: CURRENT AND FUTURE NWA PROJECTS

Company/Location	Project	Proposed In Service Date	Need	Status
NYSEG	Java Peak Shaving	2030	<1 MW peak shaving	Project is currently on hold until 2027
NYSEG	Java Microgrid	2030	4 MW redundancy (failure of existing transformer)	Microgrid will be NYSEG-owned and operated; Project currently on hold until 2027
NYSEG	Stillwater	In Service	<1 MW peak shaving power quality	In-service, Measurement and Verification until 2032
NYSEG	Ferndale Substation	2028	Sizing for peak shaving need still in progress	Project to go to RFP for a 3rd party developer solution in 2025.
NYSEG	Holland Substation	2028	Sizing for peak shaving need still in progress	Project to go to RFP for a 3rd party developer solution in 2025.

b. *provide the amount of traditional solution cost that was/will be avoided;*

Exhibit 2.13-7, below, outlines the benefits of projects which have been evaluated *through our Benefit Cost Analysis handbook.*

EXHIBIT 2.13-7: BENEFITS OF PROJECTS

Project	Total Benefits	Totals Costs	Total Net Benefits	BCA SCT Ratio
Stillwater	$6.79M	$5.10M	$1.69M	1.33
Java Peak Shaving	TBD	TBD	TBD	TBD
Java Microgrid	TBD	TBD	TBD	TBD
Ferndale Substation	TBD	TBD	TBD	TBD
Holland Substation	TBD	TBD	TBD	TBD

c. explain how the selected NWA solution enables the savings; and

Exhibit 2.13-8, below, is the list of projects that are in process and have been evaluated for benefits and savings by pursuing a NWA solution over the traditional *solution.*

EXHIBIT 2.13-8: PROJECTS

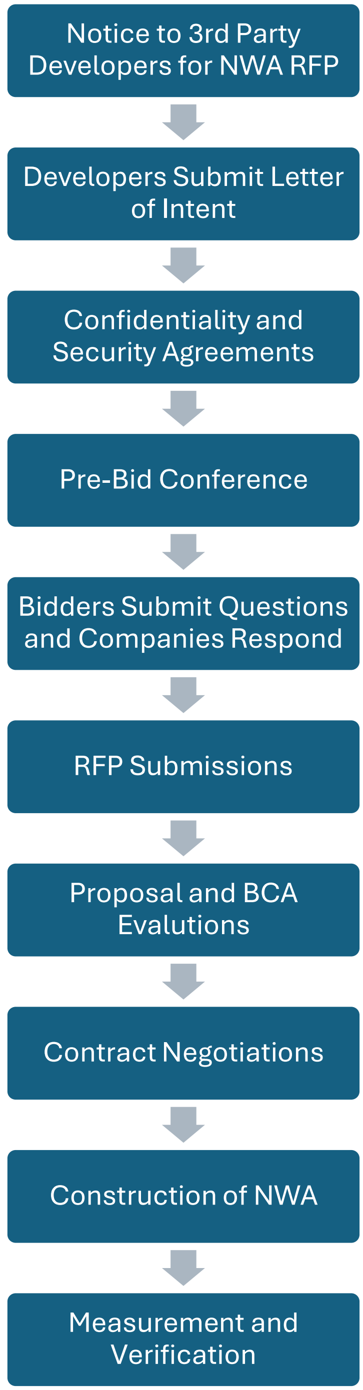
Project	*Project Benefits/Savings*
Stillwater	• Avoiding costs associated with generation capacity at the network peak; • Avoiding costs associated with transmission capacity infrastructure; and • Deferring the need to build the traditional solution, resulting in avoided distribution capacity infrastructure costs.

d. describe the structure and functional characteristics of the procurement transaction between the utility and the solution provider(s).

This question calls for disclosure of commercially sensitive information. Publication of such information could result in harm to the Companies, our customers, and the contracting NWA party. For this reason, we restrict public information to a description of the project which generally includes the NWA technology, location, and term of the deferral.

An overview of the structure and functional characteristics of the procurement transaction at a high level between the utilities and solution provider is shown in Exhibit 2.13-9:

EXHIBIT 2.13-9: STRUCTURE AND FUNTIONAL CHARACTERISTICS OF THE PROCUREMENT TRANSATION



3. DSIP Governance

The DSIP Update should clearly and fully describe <u>how the utility's DSIP activities and resources are organized and managed.</u> The information provided should:

1. Describe the DSIP's scope, objectives, and participant roles and responsibilities. A participant could be a utility employee, a third party supporting the utility's implementation, or a party representing one or more stakeholder entities.

Our 2025 DSIP Update provides our plans to: develop the electric system to accommodate clean DERs and electrification; operate the electric system safely, reliably and efficiently, while leveraging the capabilities of DERs; and enable customer access to energy services and markets to increase the value of investments of an integrated electricity infrastructure. The 2025 DSIP Update also provides the Companies progress around the efforts related to the three core DSP functions: DER Integration; Information Sharing; and Market Services, as well as other topics that are integral to our performance as the DSO.

A team of NYSEG, RG&E, and AVANGRID employees that support the OPCOs contributed to the development of the 2025 DSIP. Many of these employees are subject matter experts and have responsibilities that involve DSO activities including Integrated Planning, Grid Operations, Market Services and Information Sharing. In this respect, their DSIP responsibilities are integrated into their daily work responsibilities in managing and executing DSP functions. Externally, we rely on technology and service vendors to support our DSP functions when efficient to do so.

We have collaborated and engaged with stakeholders over the past two years, working with the Joint Utilities and separately as NYSEG and RG&E. We work with these stakeholders in performing our DSO role. Over the past two years, the Joint Utilities continued to issue quarterly newsletters and held semi-annual webinars with our DSP stakeholders. The Joint Utilities continue to maintain their website (www.jointutilities ofny.org) to provide resources to interested stakeholders. We have also participated on numerous Joint Utilities working groups.

2. Describe the nature, organization, governance, and timing of the work processes that comprise the utility's current scope of DSIP work. Also describe and explain how the work processes are expected to evolve over the next five years.

As previously mentioned, many of the employees involved in the 2025 DSIP Update are subject matter experts and have day to day responsibilities involving DSO activities - Integrated Planning; Grid Operations; Market Services; and Information Sharing.

4. Marginal Cost of Service ("MCOS") Study Link

DPS Staff recommends that the DSIP Update should include a publicly accessible web link to the latest version of the utility's Marginal Cost of Service Study.

The Companies are actively engaged in the ongoing MCOS proceeding.[152] The NY PSC issued an MCOS Order[153] requiring the Companies to file an MCOS study on or before, June 30, 2025. NYSEG and RG&E's MCOS Study can be found through the link to the MCOS proceeding on the NY DPS DMM system, which includes the latest MCOS Study. Refer to the following link:

https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=19-E-0283&CaseSearch=Search

[152] Case 19-E-0283, Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies.

[153] Case 19-E-0283, Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies, Order Addressing Marginal Cost of Service Studies (issued and effective August 19, 2024).

5. Benefit Cost Analysis ("BCA")

BCA Handbook

DPS Staff recommends that the DSIP Update should include a publicly accessible web link to the latest version of the utility's BCA Handbook.

BCA Calculations

DPS Staff recommends that BCA calculations should be transparent and publicly available, including the individual cost and benefit input parameters defined in the BCA framework order.

NYSEG and RG&E's electric BCA Handbook and BCA Calculations are being filed concurrently with the Companies' 2025 DSIP Update and will be available by searching for Case 16-M-0411[154] on the DPS website or using the following link:

https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-M-0411&CaseSearch=Search

The electric BCA Handbook and BCA Calculations will also be available on the Joint Utilities of New York website using the following link:

https://jointutilitiesofny.org/utility-specific-pages/system-data/dsips

[154] Case 16-M-0411, In the Matter of Distributed System Implementation Plans.

6. Web Links to NYSEG/RG&E Data

NYSEG and RG&E make information and tools available to customers and stakeholders on the web.

System Planning

Hosting Capacity Map Portal

NYSEG and RG&E have developed nodal-level hosting capacity and made it available to third parties on a portal.

Link:

NYSEG/RG&E Hosting Capacity Map

DER Developer Portals

The Companies intend to develop a single, one-stop DER Developer portal, that will address all interactions with DER developers with various information, data, and insights, subject to access rights that will be developed by working with DER developers and other stakeholders, including Staff. For example, certain information may be considered commercially sensitive and DER developers will want to restrict access to their own data if it can be used for competitive purposes.

Links:

NYSEG DER Developer Portal

RG&E DER Developer Portal

Interconnections Portal and SIR Inventory

The Companies continue efforts to update their database of connected DER and improve the quality and granularity of load data that are relied upon to perform interconnection studies, where such studies are required.

The queued and installed DG information are available through the SIR Inventory Information. The SIR pre-application information is available through the online application.

Links:

A Developer's Guide to the NYSEG/RG&E Interconnection On-line Application Portal

NYSEG - Online Portal

RG&E - Online Portal

NYSEG - Queue

RG&E - Queue

Non-Wires Alternatives

The portal includes capital projects included in NYSEG and RG&E's 2023 Capital Investment Plan (CIP) Filing that passed the NWA Screening Criteria.

Links:

NYSEG - Non-Wires Alternatives

RG&E - Non-Wires Alternatives

System Data

Joint Utilities' System Data Portal

The Companies, in coordination with the Joint Utilities developed a central data portal on the Joint Utilities' website in June 2017 with links to utility-specific web portals. The system data website includes utility-specific links to an expanded range of useful information.

Links:

Joint Utilities Overview of Currently Accessible System Data

Market Services

Customer Data

Customers have and will continue to have access to their data through our customer portal.

Link:

NYSEG - Energy Manager

RG&E – Energy Manager

Energy Marketplace

An online marketplace that connects customers with products and services.

Links:

NYSEG - Smart Solutions

RG&E – Smart Solutions

7. Glossary of Industry Terms

Advanced Distribution Management System (ADMS): Refers to the platform to optimize the grid and integrates a number of utility systems to allow for a range of advanced functions, including automated outage restoration, power flow optimization, and conservation voltage reduction.

Advanced Metering Infrastructure (AMI): A metering system for measuring individual household electricity consumption at intervals of an hour or less and communicating that information at frequent intervals to the distribution utility.

Active Network Management (ANM): Refers to a control system for managing DER within system limits in real-time. ANM allows increased DER hosting capacity by incorporating various smart grid components (such as regulators, capacitors, sensors, and switches) and managing the DER watts, VARs, and/or voltage within system limits.

Aggregator: Refers to a marketer, broker, or public agency that combines the loads of multiple end-use customers to negotiate the purchase of electricity, the transmission of electricity, and other related services for these customers.

Ancillary Service: Services, such as spinning reserves, non-spinning reserves, and regulation, that support the transmission of energy from generating resources to loads while maintaining reliable operation of the network.

Automated Grid Recovery/Restoration (AGR): A system that will use automated devices to reconfigure the grid and restore power to the maximum number of customers following a system disruption. *See also Fault Location, Isolation, and Service Restoration (FLISR) below.*

Battery Storage: Refers to the use of a cell or connected group of cells to convert chemical energy into electrical energy by reversible chemical reactions and that may be recharged by passing a current through it in the direction opposite to that of its discharge. Source: NYSERDA 2017 Clean Energy Industry Report

Behind-the-Meter: Relating to technology or efforts on the end-use customer side of the electric system.

Beneficial Location: Circuits or locations on the grid where DER could help address constraints and potentially defer grid investments.

Benefit Cost Analysis: A method of evaluating all potential costs and benefits or revenues resulting from the completion of a project.

Breakers: Automatically operated devices that protect a circuit from damage due to excess current from an overload or short circuit.

Business Case: A formal justification for a proposed project or undertaking on the basis of its expected commercial benefit.

Capacitor Banks: A collection of capacitors that can be switched in and out of the circuit. Capacitors are a transmission device designed to inject power into the network.

Circuit: A conductor or a system of conductors through which electric current flows.

Climate Leadership and Community Protection Act (CLCPA): The CLCPA, passed in 2019, sets the New York economy on a path to achieve "net zero" GHG emissions. The CLCPA establishes interim target reductions relative to 1990 levels of 40% by 2030 and 85% by 2050. The CLCPA also establishes several targets for the electricity sector, including targets for solar energy, energy storage, energy efficiency, and electric vehicles.

Combined Heat and Power (CHP): A system producing both heat and electricity from a single source, often using the "waste" energy from electricity generation to produce heat.

Community Choice Aggregation (CCA): a form of group purchasing that allows local governments or other entities to pool their demand and procure energy on behalf of their customers, while using transmission and distribution service from the utility.

Community Distributed Generation (CDG): Programs that allow customers to subscribe to large-scale solar facilities, allowing customers to support locally produced electricity generation through monthly bill credits.

Customer Information: Data pertaining to customer energy usage and account information.

Customer Relationship Management and Billing System (CRM&B): The Companies are planning a billing system upgrade using CRM&B, which will provide individualized customer experience to improve the Companies' customer engagement.

Cyber Security: The process of protecting data and information systems from unauthorized access, use, disclosure, disruption, modification, or destruction.

CYME: Refers to a distribution software suite of applications to analyze power flows.

Data Access Framework (DAF): Along with the Integrated Energy Data Resource (IEDR), the NY Public Service Commission (PSC) has established a DAF to govern the methods to access information on the IEDR. *See also IEDR below.*

Data Analytics Platform: Refers to the platform on which Grid Operations and other business areas will compile and analyze data to optimize systems.

Data Privacy: Refers to requirements of utilities to ensure that customer usage, billing, and other information is not released either through data breaches or interactions with third parties. Utilities ensure customer data privacy through a combination of measures, including removing personally identifiable information and/or providing third parties with aggregated data to ensure customer privacy.

DC Fast Charging: Stands for Direct Current Fast Charging; these can charge electric vehicles must faster than Level 1 and Level 2 charging stations. There are 3 standard levels of EV charging. All electric cars can charge on levels 1 (charge time: 8-15 hours) and 2 (charge time: 3-8 hours). Only certain types of EVs can charge on level 3 (charge time: 20 minutes-1 hour).

Demand Response (DR): Refers to utility programs that send price signals to customers to lower energy consumption, particularly during times of peak energy consumption, such as hot summer days.

Demand Side Management (DSM): The planning, executing, and monitoring of utility activities designed to help customers use electricity more efficiently.

DER Developer: A person or entity that develops, owns, or controls the means of DER generation and looks for ways to combine technologies to improve performance and efficiency of DERs.

DER Management System (DERMS): Software to improve an operator's real-time visibility into the status of distributed energy resources and allows distribution utilities to have more granular control and flexibility to manage grid assets.

DER Market Management System (DER MMS): Refers to the system that will help manage settlement and market transactions as a full distribution-level transactive market is developed and in place. As DER products and services mature, a DER MMS will be required to manage the market and track transactions, perform market clearing, support Measurement and Verification, and settle transactions.

DER Sourcing: DER sourcing allows DERs to provide services as an alternative to distribution capital or operational costs.

Dispatchable: A generator or load that can respond to real-time control.

Distributed Energy Resources (DERs): DERs includes end-use energy efficiency, demand response, distributed storage, and distributed generation. DERs will principally be located on customer premises but may also be located on distribution system facilities.

Distributed Generation (DG): Electrical generation and storage performed by a variety of small, grid-connected devices.

Distributed System Implementation Plan (DSIP): A vision for the electric industry and the expected changes over the next five years, along with progress made and plans to invest in enabling technologies.

DSIP Filing: A Commission-required filing by each NY electric utility addressing its current system status and identifying changes to progress towards the achievement of REV goals.

Distributed System Platform (DSP): A flexible platform for new energy products and services that incorporates DERs into distribution system planning and operations to improve overall system efficiency and to better serve customer needs.

Distribution: The delivery of energy to retail customers. This includes the system of equipment connecting between transmission and end customers.

Distribution System: The portion of the electric system that is composed of medium voltage (69 kV to 4 kV) substations, feeders, and related equipment that transport the electricity commodity to and from customer homes and businesses and that link customers to the high-voltage transmission system.

Distribution System Operator (DSO): A functional entity of an electric utility and retains the traditional responsibilities of providing safe, reliable electric service for customers. However, the DSO functions within an energy system that integrates numerous distributed energy resources (DERs) and intelligent loads connected throughout the network. The DSO helps the utility serve an increasingly diverse customer group, including energy consumers, producers, and aggregators.

Distribution System Performance: Refers to power quality and the response and/or control of grid assets to meet operational needs.

Distribution System Status: Refers to the status of real-time system conditions, including power quality, outage information, and equipment condition (such as alarms for equipment problems).

Earnings Adjustment Mechanism (EAM): Incremental performance incentives that utilities, as a DSP, can earn in return for achieving REV objectives. Source: REV Connect.

Electronic Data Interchange (EDI): EDI is the electronic exchange of business information in a standardized format between business entities.

Energy Control Center (ECC): ECCs function as a DSP and distribution grid operator. They work to optimize the grid based on changing network conditions, and maximize the utilization of grid-side, supply-side, and demand-side resources.

Energy Efficiency (EE): Refers to the goal to reduce the amount of energy generated for a given purpose.

Energy Storage: A device that can store energy and release the energy on demand.

Electric Vehicle Supply Equipment (EVSE): Equipment that supplies electric energy to recharge electric vehicles (EVs).

Electric Grid: A system of synchronized power providers and consumers connected by transmission and distribution lines and operated by one or more control centers.

EV Readiness Framework: A framework developed by the Joint Utilities to address priorities regarding infrastructure planning, education, and outreach, forecasting EV growth, and demonstration and pilot programs related to EV adoption.

Fault: On a transmission or distribution line, an abnormal flow of electric current, e.g., an open circuit (an interruption in the flow) or a short circuit (a flow that bypasses the normal load).

Fault Location, Isolation, and Service Restoration (FLISR): A system that will use automated devices to reconfigure the grid and restore power to the maximum number of customers following a system disruption. *See also Automated Grid Recovery/Restoration (AGR) above*.

Federal Energy Regulatory Commission (FERC) Order 841: FERC Order 841 was issued on February 15, 2018, and directs regional grid operators to remove barriers to entry for energy storage resources in wholesale power markets.

FERC Order 2222: FERC Order 2222 was issued in September 2020, enables DERs to participate in regional wholesale power markets through aggregations alongside traditional resources, which will enhance competition and lower consumer costs and provide additional grid resiliency.

Feeder: Primary distribution lines leaving distribution substations.

Green Button Connect: Capability that allows utility customers to automate the secure transfer of their own energy usage data to authorized third parties, based on affirmative (opt-in) customer consent and control.

Grid Automation: Refers to the Companies' vision to automate all distribution control devices, including breakers, reclosers, regulators, capacity banks, switches, and supporting telecommunications networks, to allow the Companies to measure and control power flows on circuits.

Grid Model Enhancement Project (GMEP): Refers to the complete distribution model including network load and DER characteristics. The information in the GMEP will feed the Distribution Planning Tools to support effective planning (including NWA analysis), to calculate hosting capacity, and to analyze interconnection requests, and will also feed the ADMS as the basis for power flow calculations for optimization and congestion management.

Grid Modernization: Refers to foundational technologies and investments to improve the reliability, resiliency, and automation of the transmission and distribution system, thus contributing to a more efficient and modern grid. There are three foundational grid modernization investments: AMI, Grid Automation, and Telecommunications/IT. These technologies and investments provide the raw, granular, time-differentiated data required by DSP enabling technologies, and support energy storage and other DERs.

Grid Operations: The core function that monitors and operates the distribution grid to provide safe, reliable, and resilient distribution service.

Home Energy Management: Systems that integrate "smart" appliances, HVAC, and other systems to optimize energy use based on granular data.

Hosting Capacity: The amount of DERs that can be accommodated without adversely impacting power quality or reliability without the need for grid upgrades paid for by DER developers.82

Integrated Energy Data Resource (IEDR) Platform: The NY Public Service Commission (PSC) mandated the creation and implementation of the IEDR platform. The creation of an IEDR platform will provide New York's energy stakeholders with a platform that enables effective access and use of such integrated energy customer data and energy system data. The IEDR aims to collect, integrate, and make useful a large and diverse set of energy related information on one statewide data platform. The IEDR will perform use cases to activate data into actionable insights. The IEDR will provide customer and system data to external third parties, including DER developers on a NYSERDA-based platform.

Intermittent Resource: An electric generating resource that is not continuously available. Examples include residential rooftop solar that provide output during the day.

Innovation: The development of a new method, idea, or product.

Interconnection: The result of the process of adding a Distributed Generation facility to the distribution network.

Interconnection Online Application Portal (IOAP): A platform for utility-customer engagement that allows for online application submittal, automated management and screening, and greater transparency about the interconnection process.

Interconnection Queue: The interconnection queue is the list of projects that have requested and are awaiting interconnection.

Interconnection Technical Working Group (ITWG): The Joint Utilities working group that focuses on interconnection issues.

Joint Utilities: The six electric utilities involved in REV proceedings and DSIP filings. The group is comprised of Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc. and Rochester Gas and Electric Corporation.

kW, MW: Kilowatt – A unit of electrical power, equal to 1,000 watts. Megawatt – one million watts.

kWh, MWh: Kilowatt-hour – A unit of electrical energy, equal to one kilowatt (kW) of power used for one hour. Megawatt-hour – one megawatt (MW) used for one hour. An average household will use around 800-1300 kWh per month. Source: Duke Energy Corporation.

Load: The amount of power delivered or required at a point on a system.

Locational System Relief Value (LSRV): These high-value locations provide an opportunity for DER developers to earn credit for development that relieves grid congestion in the area.

Low and Medium Income (LMI) Customers: A utility's customers who fall under a determined income threshold.

Market Design and Integration Report: A report to be filed by the Joint Utilities, identifying, and explaining their jointly planned market organization and functions, along with the policies and resources needed to support them.

Market Participant: An entity that produces and sells capacity, energy, or ancillary services into the wholesale market.

Market Settlement: Refers to the governance of DER-related contractual, program or tariff obligations and the related transactions.

Measurement & Verification: Refers to the process for quantifying and monetizing energy savings.

Measurement, Monitoring, and Control (MM&C): Refers to the ability to provide real-time visibility of grid status, as well as the ability to control resources. The grid has general MM&C capabilities to manage all resources, but the Companies are also putting in place advanced MM&C capabilities to provide better visibility and control of smaller DERs. Microgrid: a group of interconnected loads and DERs within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected and island modes.

Microgrid: a group of interconnected loads and DERs within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected and island modes.

Microgrid Management System (MGMS): Refers to an enabling technology (built on the ADMS platform) that will be developed based on the pace of community microgrid installations. Once microgrids begin serving multiple customers over the distribution network, the Companies will need to ensure reliability and service even while islanded. The MGMS will be built as an enhancement to the controls and capabilities in DERMS but will require increased measurement and control to ensure proper voltage, frequency, load balance, and power quality while islanded and re-synchronizing with the grid.

Net Energy Metering: A billing arrangement that provides credit to solar system owners for the value of the electricity that they add to the grid. The electricity meter runs backwards to provide a credit against the amount of electricity consumed from the grid.

Network: An interconnected system of electrical transmission lines, transformers, switches, and other equipment connected in such a way as to provide reliable transmission of electrical power from multiple generators to multiple load centers. Source: Duke Energy Corporation.

New York Department of Public Service (NYDPS, DPS): The state agency established by law with oversight responsibilities regarding the operation of regulated monopoly utilities.

New York Independent System Operator: The organization that monitors the reliability of the power system and coordinates the supply of electricity around New York State and facilitates the NY wholesale market.

New York Public Service Commission (NYSPSC, PSC): A five-member Commission within the Department of Public Service with the authority to implement provisions of the Public Service Law.

New York State Energy Research and Development Authority (NYSERDA): An organization governed by a 13-member Board that works with stakeholders throughout NY to develop, invest and foster the development of clean energy.

Non-Wires Alternative: Projects that allow utilities to defer or avoid conventional infrastructure investments by procuring distributed energy resources (DERs) that lower costs and emissions while maintaining or improving system reliability.

NWA Suitability Criteria: Refers to the criteria developed with the Joint Utilities and other stakeholders in assessing NWAs as an alternative to traditional wires investments.

Off-Peak: The period of relatively low system demand, often occurring in daily, weekly, and seasonal patterns.

Outage: The period during which a generating unit, transmission line, or other facility is out of service.

Outage Management System (OMS): Refers to a system to manage power outages that integrates automation capabilities for faster outage identification and response.

Peak: Relating to the period of high system demand.

Photovoltaics (PV): devices that generate electricity from sunlight through a process that occurs naturally in semiconducting materials.

Portal: specially designed Web page that brings information together from diverse sources in a uniform way.

Power Flow Model: Refers to a simulation that models power flows on the Companies' system, as well as how power flows between the NYISO transmission system.

Power Quality: A measurement of the extent to which a steady supply voltage stays within the prescribed range.

Recloser: Reclosers are small circuit breakers located at the top of distribution poles. They isolate a section of the feeder in fault conditions and thereby minimize the number of customers without service. Since they act as small circuit breakers, they have the capability to restore power automatically in temporary fault situations.

Reforming the Energy Vision (REV): A comprehensive energy strategy for New York, involving informed energy choices, new products and services, environmental protection, and new jobs and economic opportunities. The initiative involves regulators, utilities, and third-party companies.

REV Demonstration Project: Projects developed by the six large NY investor-owned electric utilities consistent with guidelines of the Track One REV proceeding. These projects aim to demonstrate new business models for third parties and the electric utilities, testing the potential of different aspects of REV.

Regulators (Voltage): Voltage regulators are electronic circuits providing stable direct current (DC) voltage independent of current, temperature, and/or alternating current (AC) voltage changes.

Reliability: A measure of the ability of the system to continue operation while some lines or generators are out of service. Reliability deals with the performance of the system under stress.

Remote Terminal Unit (RTU): A remotely controlled unit that gathers accumulated and instantaneous data to be telemetered to a specified control center which displays the status of the generation facility.

Renewable Energy: Energy that is generated from natural processes that are continuously replenished; sources include sunlight, geothermal heat, wind, tides, water, and various forms of biomass.

Request for Proposals (RFP): a solicitation, often made through a bidding process, by an agency or company interested in procurement of a commodity, service, or asset, to potential suppliers to submit business proposals.

Resiliency: Preparation and adaptation to changing conditions, along with the ability to withstand and recover quickly from disruptions.

Roadmap: A high-level plan and overview to support strategic and long-term planning, accompanied by short-term goals with specific solutions.

Smart Home: A residence that uses internet-connected appliances and devices to enable remote monitoring and management of systems such as lighting and heating.

Smart Inverter: An electronic power converter that converts direct current alternating current (inverting) and provides grid support.

Smart Meter: An electronic device that records electricity consumption and communicates the information to the utility, enabling two-way communication and more granular data.

Smart Partner Program: Partnership with community organizations to test engagement strategies for our LMI customers

Standardized Interconnection Requirements (SIR): State requirements that resources must meet to connect with the distribution system.

Substation: Facility equipment that switches, changes, or regulates electric voltage. An electric power station serving as a control and transfer point on a transmission system and serving as a delivery point to industrial customers.

Supervisory Control and Data Acquisition (SCADA): Generally, from DOE, "systems [that] operate with coded signals over communications channels to provide control of remote equipment of assets." Source: DOE (2017)

Time-Varying Pricing (TVP): Pricing electricity to vary throughout the day – this can involve a few periods or blocks throughout the day, or more frequent hourly differences. TVP requires advanced metering technology and may shift demand to lower-priced times.

Track One Order: Also known as the Order Adopting Regulatory Policy Framework and Implementation Plan, a filing issued by the Commission in February 2015 that articulates a transformation to a future electric industry in NY, incorporating distributed resources and dynamic management. The Order requires electric utilities to provide DSP services to enable the integration of DERs.

Track Two Order: A filing issued by the Commission in May 2016 that creates a new regulatory model incentivizing utilities to take actions to achieve REV objectives by better aligning utility shareholders' financial interest with customers' interests.

Transformer Load-tap-changers: Refers to a voltage regulating device located on substation transformers.

Transmission: An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Use Case: A well-defined application of a technology that identifies the actors, processes involved, and output of the application, sometimes including the goals met or problems solved.

Value of DER (VDER): A new mechanism designed by the NYSPSC to compensate DER, effectively replacing net energy metering. VDER compensates projects based on when and where they provide electricity to the grid.

VAR: Volt-ampere Reactive, A unit by which reactive power is expressed in an AC electric power system. Reactive power exists in an AC circuit when the current and voltage are not in phase.

Voltage: The difference in electrical potential between any two conductors or between a conductor and ground. It is a measure of the electric energy per electron that electrons can acquire and/or give up as they move between the two conductors.

Voltage-Var Optimization (VVO): A process that optimizes circuit performance and reduces line losses, managing circuit level voltage in response to the varying load conditions.

Wholesale Market: The purchase and sale of electricity from generators to resellers (who sell to retail customers), along with the ancillary services needed to maintain reliability and power quality at the transmission level.

Zero Emission Vehicle (ZEV): a vehicle that emits no exhaust gas from the source of power.